Sequentially coupled THMC model for CO$_2$ geological sequestration into a 2D heterogeneous saline aquifer

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**A B S T R A C T**
The significance of thermal-hydrological-mechanical-chemical (THMC) interactions is well recognized in the operation of CO$_2$ geo-sequestration. Geo-mechanical and geochemical effects may significantly affect aqueous phase composition, porosity and permeability of the formation, which in turn influence flow and transport. The TOUGHREACT simulator has the capability to quantitatively simulate fluid flow, solute transport and geochemical reaction in CO$_2$ geo-sequestration using sequential coupling. Using a mean stress formulation, geochemical effects such as stresses, displacements, and rock deformation in CO$_2$ sequestration have been simulated by the recently developed TOUGH2_CSM. Based on these simulators, in this paper a novel mathematical model of the THMC processes is developed. A sequentially coupled computational framework is proposed and used to simulate reactive transport of water, CO$_2$ gas and species in subsurface formation with geomechanics. The novel frameworks are designed to keep a generalized computational structure for different THMC processes. The coupled THMC simulators focus on: (1) fluid and heat flow, solute transport within a three-phase mixture, (2) stresses and displacements related to the mean stress, (3) non-isothermal effects on fluid properties and reaction processes, and (4) the equilibrium and kinetics of fluid-rock and gas-rock chemical interactions. A set of partial differential equations is presented to model the THMC processes of the fluid and heat flow, solute transport in aqueous and gaseous phase, mean stress, and geochemical reactions under both equilibrium and kinetic conditions. A 2D reactive transport model with complex chemical compositions is presented to analyze the THMC processes quantitatively on the coupled effects of geochemical reaction and geomechanics during CO$_2$ geo-sequestration process. The model is able to analyze the long term fate of CO$_2$ and the efficacy of different trapping mechanism (structural, residual, solubility and mineral trapping) with respect to key minerals. The modeling algorithm can also be used to simulate CO$_2$ EOR and other secondary and EOR processes in petroleum reservoirs.

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1. Introduction

Based on the technical report of Intergovernmental Panel on Climate Change (IPPC), the concentration of CO$_2$ existing in the atmosphere was 280 parts per million by volume (ppmv) at the beginning of the Industrial Revolution in the 18th century, and it increased to around 380 ppmv in 2006. The concentration of CO$_2$ in the air has been increased by one third over the past 150 years, and is currently still rising by about 1.7 ppmv every year (IPCC, 2007). While CO$_2$ reacting with the molecules of water in the atmosphere, soil and ocean system, carbonic acid and hydrogen ions are formed, leading to an acidized environment. About 35% of the CO$_2$ emissions in the atmosphere dissolves into the aqueous system of the oceans (Millero, 1995). The pH value of the acidized ocean system has decreased by 0.1 units since pre-industrial times (IPCC, 2007). The ecosystems in the ocean are influenced by aqueous acidification and the concentration reductions of associated carbonate ion (Orr et al., 2005). Only 25% of CO$_2$ emissions to the atmosphere by human activities can be absorbed and utilized by the terrestrial biosphere (Feely et al., 2004), thus CO$_2$ emissions can increase the acidities of soil, river, lake, sea and air. Therefore, CO$_2$ geo-sequestration into saline aquifers is the most effective solution to reduce CO$_2$ emissions into the atmosphere. Saline aquifers have the largest volumetric capacity among the many options for long term geological storage of CO$_2$ (IPCC, 2005).

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1.1. Physical mechanisms of CO$_2$ geo-sequestration

Saline aquifers are porous geological reservoirs with large volumes and great depths, and saturated with brine solutions, which are always rich in a certain amount of mineral ions. The sketch of CO$_2$ geo-sequestration is shown in Fig. 1. The most favorable sequestration sites are sealed by thick low-permeability layers of shale or clay, where to trap the immobile CO$_2$ permanently, to adsorb CO$_2$ on the surfaces of micro-pores, or to convert gaseous CO$_2$ into solid rock minerals. After a large amount of CO$_2$ is injected into the aquifers, there are several primary mechanisms controlling the percolation and ultimate fate of CO$_2$ (IPCC, 2005). The effectiveness of geological storage depends on a combination of the important trapping mechanisms. All kinds of the primary flow and transport mechanisms can be categorized into these three mechanisms contributing to trap CO$_2$ gas (IPCC, 2005):

Stratigraphic and structural trapping. The physical trapping of gaseous CO$_2$ below cap-rocks and above bed-rock, such as shale or clay seals with ultra low permeabilities, is the primary means to sequester gaseous CO$_2$ in geological reservoirs. CO$_2$ injected in the saline aquifer can be sealed between the caprock and the bedrock. Both the free CO$_2$ gas phase and two phase mixture are trapped in this manner. Such stratigraphic traps are often located in sedimentary basins, and are occupied by saline water, oil and gas. Structural trapping are resulted from the variations of rock types caused by changes in the way the sediments were deposited. After the CO$_2$ injection into the saline aquifer, two phase mixture will be formed rapidly. The pressure will increase rapidly accordingly, which results in significant geo-mechanical effects in the formation. By the maximum extent of geo-mechanical effect during the CO$_2$ injection period, faults can be activated as favorable leaking pathways of gaseous CO$_2$. This mechanism usually operates over large spatial scales (field size) but short timescales (injection period).

Solubility trapping. It occurs in the saline aquifers where fluids transport very slowly over long distances. After CO$_2$ is injected into the aquifer, it displaces aqueous water and migrates upwards. Under the formation pressure, gaseous CO$_2$ becomes equilibrated with formation water, leading to CO$_2$(aq) in the formation water. This process follows phase and chemical equilibrium conditions under the formation pressure. Over time, a large amount of gaseous CO$_2$ dissolve in the aqueous water of the formation. Dispersion and fingering of aqueous CO$_2$ may be formed due to permeability heterogeneity, gravity override and mobility contrast between CO$_2$ and formation fluid. These mechanisms also operate over relatively short timescales (injection period).

Mineral trapping. After gaseous CO$_2$ is dissolved into formation water (separate phase may still be there), carbonic acid is released to dissolve certain amount of rock minerals, leading to a rise of the pH value. Dissolved ions and minerals may further react to form stable carbonate and silicate minerals. Reaction of dissolved CO$_2$ with minerals can be very rapid (days) for some carbonate minerals, but very slow (hundreds to thousands of years) for others (silicate minerals). Precipitation of carbonate minerals leads to the continuous reaction of bi-carbonate ions with metal ions (e.g. iron, calcium, and magnesium), which are released by the dissociation of the silicate minerals (e.g. clay, chlorite, feldspar and mica). This mechanism operates over long timescales (thousand years) and relatively small size scale (formation scale).

1.1.1. Important rock minerals for trapping CO$_2$

From the existing reactive transport simulations (Audigane et al., 2007; Balashov et al., 2013; Gaus et al., 2005; Gunter et al., 2000; Johnson et al., 2001; Ketzer et al., 2009; Kihm et al., 2012; Knauss et al., 2005; Liu et al., 2011; Mito et al., 2008; Raistrick et al., 2009; White et al., 2005; Wigand et al., 2008; Xu et al., 2003, 2004a, 2004b, 2005, 2007; Zerai et al., 2006), I can summarize that the general mineralogy composition that could be present in the potential CO$_2$ geo-sequestration sites can be categorized into two kind: carbonate minerals (i.e., calcite, magnesite, dawsonite, siderite, ankerite, etc.) and silicate minerals (i.e., quartz, oligoclase, smectite, feldspar). Among these previous numerical simulations, the contribution of mineral trapping is significant when plagioclase feldspar minerals and chloride minerals present in the chemical reaction system, especially for the reactive transport simulations by Xu et al. (2003, 2004a, 2004b, 2005). It is obvious that the quartz, plagioclase feldspar minerals, chloride minerals, kaolin minerals and illite minerals are the common minerals selected for the numerical simulation of mineral trapping in Fig. 2. Among the precipitated minerals by mineral trapping in Fig. 3, eighteen of these twenty numerical models mentioned the generation of dawsonite as secondary mineral. Sixteen of these twenty numerical models mentioned siderite and ankerite as secondary minerals. Twelve of them mentioned smectite as a secondary mineral. Since the chlorite has been concluded as a key minerals for the mineral trapping of CO$_2$ in formation rock (Kihm et al., 2012), other minerals such as oligoclase that may play a significant role for the mineral trapping will be studied in this research. The general mineralogy investigated in this study is selected from the key minerals with high frequency of presence in these twenty numerical simulations.

1.1.2. Chemical reaction pathway

The chemical reaction pathway depends upon rock compositions. According to the mineral compositions of the CO$_2$ geo-sequestration sites, the most common formations are categorized into three kinds: sandstone, carbonate and clay. In terms of the rock type, the rock minerals in these three formations are quite similar, but the volume fractions of the rock minerals vary significantly. These formations are always composed of quartz, carbonate minerals, plagioclase feldspar minerals, clay minerals, and minor other components. Calcite represents the carbonate minerals. Oligoclase and K-feldspar represent the plagioclase feldspar minerals. Clay minerals includes kaolinite group (kaolinite), illite group (illite), smectite group (smectite- Na and smectite- Ca) and chlorite group (chlorite). Furthermore, the chemical reaction pathway after supercritical CO$_2$ injection can be described in terms of rates of the kinetic reactions. Based on the parameters of the kinetic rates by Xu et al. (2003, 2004a, 2004b, 2005), the kinetic reactions rates are small but vary significantly for different rock minerals. Carbonate minerals have the fastest kinetic reaction rates (in the magnitude of $10^{-7}$ mol/m$^2$s), then plagioclase feldspar minerals have the kinetic reaction rates in the magnitude of $10^{-12}$ mol/m$^2$s, illite minerals and smectite minerals have the kinetic reaction rates in the...
magnitude of $10^{-13}$ mol/m² s, kaolin minerals and quartz have the kinetic reaction rates in the magnitude of $10^{-14}$ mol/m² s. The kinetic chemical reaction rates are also related to the reactive surface area of rock, the acid or base mechanism involved in the aqueous phase, the activation energy and temperature.

In terms of the rock mineral compositions and kinetic rates, the chemical reaction pathway can be described in Fig. 4. Every small pore can be treated as a batch reactor when supercritical CO₂ invades it. The CO₂ dissolution is the fastest chemical reaction, the chemical equilibrium of CO₂ dissolution is reached simultaneously with the injection of supercritical CO₂. It releases large amounts of hydrogen ion, leading to an acidized aqueous environment. This process is an acidized process. Secondly, the carbonate minerals such as calcite, dolomite, magnesite start to dissolve into the aqueous phase. Various iron species and bicarbonate species are releasing into the aqueous phase. The rates of the carbonate mineral dissolution are in the magnitude of $10^{-7}$ mol/m² s, and the dissolution of carbonate minerals reaches the equilibrium state rapidly. Thirdly, the rock minerals from plagioclase group, kaolin group, illite group, smectite group and chlorite group starts to dissolve into the aqueous phase under the effects of chemical species $H^+$. This process is defined as pH buffering. The minerals break into large amounts of different chemical species in aqueous phase. K-feldspar and chlorite are taken as examples to illustrate how the minerals dissociate into different chemical species in Fig. 4. It may take thousands of years for the minerals dissolutions. These three processes are dissolutions of gas and minerals. After this, the new minerals precipitate into the solid phase on the surface of the formation. The new minerals are mainly composed of stable carbonate mineral such as dawsonite, ankerite and siderite. The precipitation of the new minerals are relatively fast in the magnitude of $10^{-8}$ mol/m² s after the mineral
dissolution. Finally, the slowest reaction is the precipitation of quartz in the magnitude of $10^{-14}$ mol/m² s. The last two processes lead to the mineral trapping of supercritical CO₂ in solid phase, and continue to buffer pH value and consume the chemical species of H⁺. Based on the analysis above, the chemical reaction pathway of supercritical CO₂ with rock minerals is complicated due to the key factors (rock type, rock composition, reaction rate, etc.)

1.2. Numerical simulation scheme and algorithm for THMC processes

For the numerical simulations of the THMC processes, THM processes and THC processes are always coupled separately to solve different problems in both systems. Among many factors of the THMC processes to be considered in the numerical models, the geomechanical effects take place immediately after the working fluid injection, leading to pore structure change and land subsidence. The geochemical reactions that take place between injected working fluid (i.e., CO₂ gas), formation water and the rock minerals are much more complex than the others, and are more important to determine the long term fate of supercritical CO₂ in saline aquifers. These geochemical reactions have a significant role in the related transport processes, for example, through chemical precipitations in the pore or fracture spaces affecting porosity and permeability, or dissolved CO₂ decreasing the density of formation fluid resulting in buoyant flow fluxes. It is a challenging issue to model the THMC processes within a coupled procedure mathematically, because of the complexity of multiphase fluid and heat flow, geomechanics, geochemical reactions of water-gas-rock, and the strong non-linearities in the mass, energy and momentum conservation equations. Among the four processes, THM processes and THC processes are always coupled separately to solve for CO₂ geo-sequestration, but these coupled processes don’t have capabilities to address the mutual effects of thermal gradients, geomechanics and geochemistry quantitatively. It is necessary for us to develop a THMC model. There are few numerical studies to couple the THMC processes together. Among the THMC processes, the geochemical reaction process is much more complex than the others. Many numerical studies have addressed the coupled methods for TH processes. The numerical scheme and algorithm for THMC processes can be based on that of THC processes. There are two major methods widely used to solve the fluid flow, solute transport, and geochemical reactions together, i.e. direct substitution approach and sequential iteration approach. In the two approaches, the second one solves the fluid transport and the geochemistry individually and sequentially in an iterative manner (Cederberg et al., 1985; Yeh and Tripathi, 1991; Engesgaard and Kipp, 1992; Simunek and Suarez, 1994; Walter et al., 1994; Zyset et al., 1994; Xu, 1996; Wei, 2012). Furthermore, a modified sequential non-iterative approach was proposed to solve solute transport and chemistry only once without iteration (Liu and Narasimhan, 1989; Ague and Brinham, 1989; Appelo, 1994). By means of sequential iteration approach, a set of geochemical codes such as SOLMINEQ (Kharaka et al., 1989), EQ3/6 (Wolery, 1992), PHREEQC (Parkhurst et al., 1991), PATHARC (Hitchon, 1996), PHREEQC V2.0 (Parkhurst et al., 1999), GEOCHEMIST’S WORKBENCH (Bethke, 2002), TOUGHREACT (Xu et al., 1997), and UTCHEM (Delshad et al., 1996; Najafabadi et al., 2009) are designed to couple the fluid flow, solute transport, and geochemical reaction sequentially. Among them, SOLMINEQ, EQ3/6, PHREEQC, PATHARC, GEOCHEMIST’S WORKBENCH are for batch reaction systems or 1D geochemistry transport problems, and majority of these simulators track the database of geochemical reaction parameters at the every iteration. This may be not efficient or realistic to simulate a field-scale multi-dimensional reactive transport problems. TOUGHREACT and UTCHEM are developed to solve the multi-dimensional and multi-phase fluid flow, solute transport, and chemical reactions in groundwater and petroleum systems, respectively. UTCHEM does not consider the kinetic reactions. The second method, direct substitution approach, substitutes the geochemical reaction into fluid flow equations directly, forming a fully coupled reactive solute transport model. There are few studies of the fully coupled approach (Zhang et al., 2012a, 2012b; Zhang, 2013; Xiong et al., 2013; Wu et al., 2014), it solves the fluid flow, solute transport, and geochemical reactions simultaneously with a high accuracy, but it might consume lots of computer resources than the sequential iteration approach. Therefore, the sequential iteration approach is sufficient for us to couple THMC processes together, in order to avoid the calculation complexity.

There are many developments for the algorithm of THM models.
The gaseous, aqueous, and solid phases are involved in heat flow, fluid flow, geomechanics, and geochemical reactions. The effects of heat, pressure, and stress are taken into account for the calculation of physical, geomechanical, and geochemical properties. Multiphase Darcy flow formulation is applied for the fluid flow in porous media. A simplified mean stress formulation is used in this THMC model. Transport of aqueous and gaseous species by advection is taken into account. Any kind of chemical species in liquid, gas, and solid phases can be simulated in this model. Thermodynamic equilibrium is considered between gaseous species and the corresponding aqueous species. Aqueous complexation and gas dissolution are considered under the local equilibrium assumption. Thermodynamic and chemical equilibrium are attained instantly within each grid cell. Mineral dissolution and precipitation predefined in the model can occur either under local equilibrium or kinetic conditions.

For the sequentially coupled THMC model, it has three main parts to solve the THMC processes. The first part is fluid flow, heat flow, and geomechanics. The second part is solute transport. The last part is chemical reaction module. The first part is an independent procedure, which is solved in a fully coupled process. After this, the second part of solute transports for gaseous species and aqueous species are solved to obtain the total concentrations of primary chemical species. Finally, the chemical reactions are solved to obtain the geochemical compositions in the geochemical system in every grid cell. Among these three main parts, the solute transport and chemical reaction is solved in a sequential manner with an iterative procedure. The mathematical equations for numerical algorithms are described as below.

2.2 Fluid flow, heat transfer and geomechanical equations

The mathematical equations for fluid flow, heat flow, and geomechanics are described in the following part.

2.2.1 Mass conservation equation

In the sequentially coupled procedure, the first part only solve the mass balance for a certain number of primary components (i.e., H₂O, NaCl, and CO₂), mass loss or gain of primary components in chemical reactions are considered in the equation. The mass balance for primary components  \( k \) in accordance to Darcy’s law can be written in the following form:

\[
\frac{dM^k}{dt} = \nabla \cdot F^k + q^k + R^k
\]

The quantity \( M \) is the accumulation term, representing mass of a primary components or species, with \( k = 1, \ldots, N_k \) is the primary components or species \( (H_2O, NaCl, and CO_2) \). \( F \) is the mass flux based on the Darcy’s Law, and \( q \) is sinks and sources of primary components. \( R \) denotes mass or loss for \( H_2O \) and \( CO_2 \) due to chemical reactions, which are the feedbacks from the third part of geochemical reaction module.

2.2.2 Energy conservation equation

The energy balance equation is derived under the assumptions that energy is a function of temperature only and energy flux in the porous media occurs by advection and heat conduction only.

\[
\frac{dU}{dt} = \nabla \cdot F_{\beta} + q_h
\]

where \( U \) is the heat accumulation term of rock and fluid, \( F_{\beta} \) is the heat flux, and \( q_h \) is the heat sink and source by heat injection and withdraw.

2.2.3 Mean stress equation

The mean stress equation in this THMC model is based on the...
equation by Winterfeld et al. (Winterfeld et al., 2012), which is to solve the normal mean stress. The mean stress equation is given below.

\[ \frac{3(1-v)}{1+v} \sigma^2_{\text{rms}} - \frac{2(1-2v)}{1+v} \left( \alpha \nabla^2 p + 3 \beta K B_i K \theta T \right) + \nabla \cdot \mathbf{F} = 0 \]  

(3)

where \( v \) is the Poisson’s ratio, \( \tau_{\text{ms}} \) is the normal mean stress, \( \alpha \) is the Biot’s coefficient, \( p \) is the pore pressure, \( \beta \) is the linear thermal expansion coefficient, \( K \) is the bulk modulus, \( F \) is body force, \( \iota \) is the Lame’s constant, \( C \) is the shear modulus, \( T \) is the temperature, and subscript \( m \) is the label of mean stress.

2.3. Discretization and solution method for fluid and heat flow, geomechanics

The mass balance equation, energy balance equation and mean stress equation are discretized as follows:

2.3.1. Mass balance

The mass balance equations (Eq. (1)) are discretized in space using the integral finite difference method. Introducing appropriate volume averages, then

\[ \frac{dM_n}{dt} = \frac{1}{V_n} \sum_m A_{nm} F_{nm} + q_i - R_n^{k} \]  

(4)

where \( M_n \) is the average value of \( M \) over \( V_n \). Surface integrals are approximated as a discrete sum of averages over surface segments \( A_{nm} F_{nm} \) denotes mass flux between two volume elements \( V_n \) and \( V_m \), and \( q_i \) denotes sinks and sources by mass injection or withdraw at element \( n \).

2.3.2. Energy conservation equation

The energy balance equation (Eq. (2)) are discretized in space using the integral finite difference method. Introducing appropriate volume averages, then

\[ \frac{dU_n}{dt} = \frac{1}{V_n} \sum_m A_{nm} F_{nm} + q_{h,n} \]  

(5)

2.3.3. Mean stress equation

Eq. (3) expresses the mean stress in terms of the pressure and body forces. The Integral Finite Difference method is employed to discretize the mean stress equation over the volume of grid cell \( V \) towards the outer surface. The discretized form of mean stress in terms of surface integral is expressed as:

\[ M_n(\tau, p, T) = \sum_m \left[ \frac{3(1-v)}{1+v} \sigma^2_{\text{rms}} \sigma_{nm} \right] + \frac{2(1-2v)}{1+v} \left( \alpha \nabla p_{nm} + 3 \beta K B_i K \theta T_{nm} \right) \]  

(6)

\[ A_{nm} = 0 \]

2.3.4. Equation system in residual form

For the fully coupled approach to solve the THM processes in first part, the mathematical equations for fluid flow, heat flow and geomechanics are solved simultaneously. The equation system for THM model can be written as follows:

\[ R_n^{k+1} = M_n^{k+1} - M_n^k - \frac{\Delta t}{V_n} \left[ \sum_m A_{nm} F_{nm}^{k+1} + V_n q_i^{k+1} + V_n R_n^{k+1} \right] + \sum_{Nc} X_j^{k+1} \]  

\[ \kappa = 1, \ldots, Nc \]  

(7)

\[ M^{k+1} = M(X_{j,k+1}) \quad j = 1, \ldots, Nc + Np + Ng \]  

(8)

For each control volume \( V_n \), there are \( N_{eq} \) equations to describe the THM processes. The total number of the non-linear equations representing the THM system with \( N_{el} \) grid blocks is \( N_{el} \times N_{eq} \). The unknown primary variables has the same number as the equations, \( X_j, j = 1, \ldots, N_{el} \times N_{eq} \), which define the state of the THM system at a specific time step \( t^{n+1} \). The method of Newton–Raphson iteration is employed to solve the equation system. A NR iteration index \( p \) is used to expand the residuals \( R \) at iteration step \( p+1 \) by means of Taylor series expansion. The Taylor series expansions of residual equations in terms of primary variables are as follows:

\[ \sum_{j=1}^{Nc} \frac{\partial R_n^{k+1}}{\partial X_j} \left| \frac{p}{X_j^{p+1} - X_j^p} \right. = -R_n^{k+1}(X_j^p) \quad \kappa = 1, \ldots, Nc \]  

(9)

\[ \sum_{j=1}^{Nc} \frac{\partial M^{k+1}}{\partial X_j} \left| \frac{p}{X_j^{p+1} - X_j^p} \right. = -M^{k+1}(X_j^p) \]  

(10)

For the fully coupled approach in this part, the equations for fluid flow, heat flow and geomechanics are solved simultaneously until the prescribed convergence criteria are satisfied.

2.4. Solute transport for gaseous and aqueous species

After the first part is solved, the Darcy velocity for each is used to solve the second part: solute transport for gaseous and aqueous species. The governing equation for solute transport is derived from the mass conservation equation. The aqueous species are transported in the liquid phase, and they are released by the chemical reactions with gaseous, aqueous and solid phases. Transport equations are written in terms of total dissolved concentrations of primary chemical components. Advection and diffusion of chemical species are considered in the reactive transport processes, and the coefficients of diffusion are set to be the same for different chemical species. The source or sink terms from the chemical reactions are quantified in the reactive transport equations.

2.4.1. Solute transport equation

The equation of reactive solute transport is a mole balance equation, which has the same expression of the general mass conservation of Eq. (1). The mass conservation equation become mole balance equation, and the accumulation term becomes

\[ M_j = \phi S_j C_j \quad j = 1, 2, \ldots, Nc \]  

(11)

the flux term becomes

\[ F_j = u_j C_j \left( \frac{\phi}{s_j^D} \right) \quad j = 1, 2, \ldots, Nc \]  

(12)

and the sink/source term becomes

\[ q_j = q_{j1} + q_{jg} \quad j = 1, 2, \ldots, N_c \]  

where \( N_c \) is the total number of the primary chemical components (species), \( u_j \) is the Darcy velocity of phase \( j \), \( D_j \) is the diffusion coefficient of phase \( j \). For the primary aqueous chemical species, \( C_j \) is the total concentration of the \( j \)th primary species in aqueous phase. The concentrations of the secondary species can be calculated by means of a linear combination of the concentrations of primary species. Therefore, all the moles of the secondary species can be transferred to the moles of primary chemical species. For the primary gaseous chemical species, \( C_j \) is the concentration of the \( j \)th species in gaseous phase, which is related to its partial pressure in gaseous phases, \( C_j = p_j/R_T \), \( p_j \) is the gaseous species partial pressure, \( R \) is the gas constant, and \( T \) is the absolute temperature. \( q_{j1} \) denotes sinks and sources for primary chemical species. \( q_{jg} \) denotes sinks and sources for primary chemical species in gaseous phase. \( R_j \) denotes chemical reactions for primary chemical species, which are the feedbacks from the third part.

2.5. Discretization and solution method for solute transport

Finite difference is employed to discretize the solute transport equations for gaseous and aqueous species, then a generalized form of discretized solute transport equation is as follows:

\[
\frac{\Delta t}{V_n} \sum_m A_{nm} \left[ k_{rm}^{i+1} r_{rm}^{i+1} + D_{nm} \frac{C_{jm}^{i+1} - C_{jm}^{i}}{d_{nm}} \right] = \Delta M_{nm}^{i+1} - q_{jg}^{i+1} \Delta t - q_{jn}^{i+1} \Delta t \quad j = 1, 2, \ldots, N_c \]  

where \( n \) labels the grid block, \( j \) labels the chemical component, \( N_c \) is the total number of chemical components, \( k_m \) labels the number of the time step, \( d_{nm} \) is the liquid volumetric flux or Darcy’s velocity (m/s), \( D_{nm} \) is the effective diffusion coefficient (including effects of porosity, phase saturation, tortuosity and weighting factors between the two grid blocks), \( d_{nm} \) is the nodal distance, \( R_{nm}^{i+1} \) are the overall chemical reaction source/sink terms.

According to Eq. (14), the concentration of primary chemical species and the partial pressure of the gaseous species are the unknown variables in the solute transport equation. Every unknown variable is solved once for every primary chemical species in aqueous and gaseous phases.

2.6. Chemical reaction equation

The chemical equations are solved on a grid block by grid block basis at the same time. The main equations for chemical reactions are mole balance equations for each primary chemical species and saturation index for mineral and gas species. The chemical reaction of primary species leads to the source (mass gain) or sink (mass lost), which are the feedbacks for the solute transport and fluid part in the next step iteration.

2.6.1. Mole balance equation

The mole balance equation for primary chemical species is as follows:

\[ F_j = T_j^{i+1} - T_j^i = 0 \]  

where \( T_j^i \) is the total concentration of primary chemical species at time step \( i \), and \( T_j^{i+1} \) is the total concentration of primary chemical species at time step \( i+1 \).

The mathematical expression of total concentration is as follows:

\[ T_j = c_j + \sum_{k=1}^{N_c} v_{jk} C_k + \sum_{m=1}^{N_g} v_{jm} C_m + \sum_{n=1}^{N_s} v_{jn} C_n \Delta t \]  

where \( c \) denotes concentrations of chemical species. The subscript \( j \) is primary chemical species, \( k \) is secondary aqueous complex, \( m \) is mineral under equilibrium condition, and \( n \) is minerals under kinetic constraints, \( N_c \) is the number of the corresponding aqueous complexation for secondary chemical species. \( N_p \) is the number of corresponding reactions between solid mineral and aqueous species under equilibrium, \( N_g \) is the number of corresponding reactions between solid mineral and aqueous species under kinetics. \( k_{jm} \) and \( a_j \) are stoichiometric coefficients of the primary species in the aqueous complexes, equilibrium and kinetic minerals, respectively. \( r_j \) denotes the kinetic rates, which is a function of concentrations of primary chemical species. The equation of kinetic reaction rate for minerals is given by Lasaga et al. (1994):

\[ r_n = f(c_1, c_2, \ldots, c_{N_c}) = \pm K_n A_m \left[ 1 - \Omega_n \right]^\eta \quad n = 1, \ldots, N_q \]  

where \( A_m \) is the specific reactive surface area, \( \Omega_n \) is the saturation ratio of kinetic mineral, the definition of saturation ratio is explained later. The parameters \( \eta \) and \( \eta \) are assumed to be one. The values of \( r_j \) could be positive and negative, which denote dissolution and precipitation of corresponding mineral respectively. \( b_k \) is the rate constant, which is a temperature dependent variable. It is expressed by an Arrhenius equation (Lasaga, 1984; Steefel and Lasaga, 1994), in terms of the different chemistry mechanism, dissolution and precipitation of minerals are not only catalyzed by pure \( H_2O \) (neutral mechanism), but also by \( H^+ \) (acid mechanism) and \( OH^- \) (base mechanism). The equation of \( b_k \) in terms of the three mechanisms can be expressed by (Lasaga et al., 1994; Palandri and Kharaka, 2004):

\[
k_n = k_{25}^{OH} \exp \left[ \frac{-E_a^H}{R} \left( \frac{1}{T} - \frac{1}{298.15} \right) \right] + k_{25}^{OH} \exp \left[ \frac{-E_a^H}{R} \left( \frac{1}{T} - \frac{1}{298.15} \right) \right] a_{H^+}^{OH^-} + k_{25}^{OH} \exp \left[ \frac{-E_a^H}{R} \left( \frac{1}{T} - \frac{1}{298.15} \right) \right] a_{H^+}^{OH^-} \]  

where \( E_a \) is the activation energy, \( k_{25} \) is the rate constant at 25 °C, \( R \) is gas constant, \( T \) is absolute temperature, \( a_{H^+}^{OH^-} \) is the activity of \( H^+ \), which is the product of activity coefficient (\( \gamma_{H^+} \) and concentration of \( H^+ \) (\( c_{H^+} \)), and \( a_{H^+}^{OH^-} \) is the activity of \( OH^- \), which is the product of activity coefficient (\( \gamma_{OH^-} \)) and concentration of \( OH^- \) (\( c_{OH^-} \)).

2.6.2. Saturation index for mineral at equilibrium condition

In a geochemical reaction system, the dissolution rate of a certain mineral (i.e., CaCO\(_3\)) is very fast. The reaction of the mineral is always set to be at equilibrium, the mineral saturation index controls the dissolution of the mineral, and it can be expressed as:

\[ F_m = \log \Omega_m = \log X_m^{ \gamma_{m1}^{-1} } \cdot K_m^{-1} \cdot \prod_{j=1}^{N_c} C_j^{ \gamma_{mq} } \cdot v_{jm} = 0 \]  

where \( m \) is the equilibrium mineral index, \( X_m \) is the mole fraction of the \( m \)th mineral phase, \( \Omega_m \) is its thermodynamic activity coefficient, \( K_m \) is the corresponding equilibrium constant of the equilibrium mineral, \( C_j \) is the concentration of related primary chemical species or components, \( v_{jm} \) is the stoichiometric coefficient of \( j \)th basis.
species in the \( m \)th mineral equilibrium reaction, and \( \gamma_j \) is the activity coefficient of primary chemical species.

2.6.3. Saturation index for gas at equilibrium condition

The chemical reactions between aqueous and gaseous species are set to be under a condition of local equilibrium. Based on the Mass Action Law, we obtain the following expression:

\[
F_g = \log \Omega_g = \log^{\gamma_g^{-1}} p_g^{-1} K_g^{-1} \prod_{j=1}^{N_l} c_j^{\gamma_j} \gamma_p = 0
\]  

where subscript \( g \) represents gas index, \( p \) is the partial pressure of gaseous phase, \( \Omega \) is the fugacity coefficient of gaseous species.

2.7. Discretization and solution method

There are \( N_c \) mole balance equations and \( N_m \) mineral and gas saturation index, which constitute a system with \( N_c+N_m \) primary variables. The primary variables can be defined as \( c_i (i = 1, 2, ..., N_c+N_m) \), by means of Newton–Raphson iteration, then the equations become:

\[
\sum_{i=1}^{N_c+N_m} \frac{\partial F_{fi}^{-1}}{\partial c_i} \Delta c_i = -F_{fi}^{e}
\]  

The derivatives of Eq. (21) can be calculated both analytically and numerically.

2.8. Reservoir properties calculation with THMC effects

2.8.1. Porosity

The relationship between mean stress, \( \tau_m \), and porosity, \( \phi \), has been investigated extensively (Ostensen, 1986; McKee et al., 1988; Davies and Davies, 2001; Rutqvist and Tsang, 2002), which we have incorporated into our mechanical model formulation. We begin with mechanical changes in porosity as follows:

\[
\phi_M = \phi(\tau_m)
\]  

where subscript \( M \) indicates mechanical effects on porosity and \( \tau_m \) is the current mean stress.

This THMC model is able to incorporate various correlations for stress-dependent porosity and permeability, but we can select an appropriate one for the specific filed. One example from the study by Davies and Davies (2001) is given as follows:

\[
\psi(\tau_m') = \phi_v + (\phi_0 - \phi_v) e^{\alpha \tau_m'}
\]  

where \( \tau_m' \) is the effective stress as \( \tau_m' = \tau_m - \alpha p \), \( \alpha \) is Biot coefficient, \( \phi(\tau_m') \) is the porosity at the current state of mean effective stress \( \tau_m' \), and \( \phi_v \) is residual porosity under infinite net stress or minimum porosity, \( \phi_0 \) is the porosity at zero mean effective stress.

The chemical reaction model incorporates porosity changes due to mineral dissolution and precipitation as follows:

\[
\phi_c = 1 - \frac{N_m}{m=1} f_m - f_s
\]  

where \( N_m \) is the number of reactive minerals, \( f_m \) is the total mineral fraction (\( V_{\text{mineral}}/V_{\text{medium}} \)), and \( f_s \) is the non-reactive fraction.

In the THMC processes, the porosity change within each time step \( \Delta t = \phi^{k+1} - \phi^k \) is given in terms of the changes in mechanical and chemical properties \( \Delta \phi_M = \phi_M^{k+1} - \phi_M^k \) and \( \Delta \phi_c = \phi_c^{k+1} - \phi_c^k \).

\[
\phi^{k+1} = \phi^k + \Delta \phi_M + \Delta \phi_c
\]  

2.8.2. Permeability

The permeability change is related to the porosity as follows:

\[
k^{k+1} = k(\phi^{k+1})
\]  

This THMC model is able to incorporate various correlations for permeability. One example from the study by Davies and Davies (2001) is given as follows:

\[
k(\tau_m') = k_0(1 - \phi_i)^2 \phi^{3}
\]  

where \( \phi_i \) is porosity at initial reservoir net stress, \( \phi \) is porosity at reservoir net stress, \( k(\tau_m') \) is the permeability at net stress \( \tau_m' \) and \( k_i \) is the permeability at initial reservoir net stress.

Another associated function for permeability in terms of porosity developed by Rutqvist and Tsang (2002) is

\[
k = k_0 \epsilon \left( \frac{\phi}{\phi_i} \right)^c
\]  

where \( k_0 \) is zero stress permeability and the exponent \( c \) is a parameter.

2.8.3. Capillary pressure

A change in permeability and porosity leads to a change of pore size and capillary pressure. The following J-function is included in our model to correct for capillary pressure change assuming no change in wettability of the pore surface.

\[
p_c = p_c 0 \sqrt{\frac{k_0 \phi}{k_0 0}}
\]  

3. Code structure for sequentially coupled THMC model

The solution procedure and code structure of TOUGHREACT simulator (Xu et al., 2004c) are taken as a reference for the sequentially coupled THMC model. Fig. 5 shows the flow chart of the sequential coupled THMC model. The solving sequence of the THMC simulator is as follows: the non-isothermal multiphase flow equations and mean stress equation are solved first, which results in a procedure in the first part to solve THM processes. The resulting flow velocities and saturation are transmitted into the module of reactive transport. The solute transport in the liquid phase is based on the total dissolved concentrations of primary chemical species. In addition, the transport of gaseous species is solved in terms of their partial pressures. The resulting concentrations and partial pressures from the transport calculation are used in the chemical reaction model. The temperature distribution obtained from the solution of the multiphase flow equations is used to update physical and chemical parameters. The chemical transport equations are solved component by component, whereas the reaction equations are solved on a grid block basis. The transport and reaction equations are solved iteratively until convergence.
4. Application: chemical reaction and geomechanics in 2D layered formation

This conceptual model is based on the model presented by Rutqvist and Tsang (2002) and Winterfeld and Wu (2012). The previous two models in the literature aim at describing the THM process during the CO₂ injection into a saline aquifer. The objectives of this case are to describe the THMC process of CO₂ injection in a large scale reservoir with different properties in different domains, and quantitatively analyze the impacts of heterogeneous domains on the CO₂ transport, geomechanics and chemical reactions. The setup for initial conditions in this conceptual model is different from those used in the previous models. The model details and result discussions are given below.
4.1. Model description

The dimension of the conceptual model is 70,000 m (x) × 1 m (y) × 3000 m (z). Unlike the previous THMC conceptual model, this model is not extracted from a deep saline aquifer. The depth (3000 m) is from the ground surface to the bottom of the bedrock. The initial hydrostatic pore pressure assigned to the whole reservoir domain is based on the depth of the reservoir. The initial hydrostatic pore pressure is assigned to the ground surface to the bottom of the bedrock. The initial model is not extracted from a deep saline aquifer. The depth (3000 m) is from the ground surface to the bottom of the reservoir (3000 m). The initial pore pressure at the surface is set to be the ambient pressure (about 10^5 Pa), and a higher pore pressure (about 3 × 10^7 Pa) is obtained at the bottom of the reservoir. The initial hydrostatic equilibrium condition is based on the lithostatic equilibrium calculation. The initial temperature calculation is based on the temperature gradient of 25°C/1000 m. It is set to be ambient temperature (about 10°C) at the surface and higher temperature (about 85°C) at the bottom. In addition, the initial mean stress profile for the whole simulation domain is calculated by a built-in subroutine, based on the lithostatic equilibrium condition. The initial mean stress is set to be 1 × 10^5 Pa at the surface of the reservoir (0 m) and 5 × 10^7 Pa at the bottom of the reservoir (3000 m).

The grid cell number is 201 × 1 × 100 in x, y, z directions respectively, and the detailed subdivision of the grid cells in the three directions is given in Table 1. The horizontal distance in the x direction is 70,000 m. The four boundaries are set to be closed boundaries for the pressure field and fixed stress boundaries for stress fields. The whole conceptual model is an isothermal domain throughout the simulation times, which means that the thermal gradient is kept as the original one. For this conceptual model of the THMC processes during supercritical CO₂ injection into the center at the saline aquifer domain, two cases are designed for the simulation: the first one is with four different rock domains and without a fault above the target saline aquifer, and the second one is with five different rock domains and with a fault apparent above the target saline aquifer.

The vertical section profiles of the two cases are shown in Figs. 6 and 7. For the first case, there are four different domains with different rock properties, including upper caprock, middle caprock, target saline aquifer, and lower bedrock in Fig. 6. The thicknesses of the four domains are 1200 m, 100 m, 200 m, and 1500 m, respectively. The upper caprock which is near the ground surface has a relatively higher permeability of 0.3 × 10⁻¹⁵ m². The middle caprock and lower bedrock have the same hydrological parameters with a lower original permeability of 0.3 × 10⁻¹⁷ m² and lower original porosity of 0.0094 to seal the potential saline aquifer for CO₂ storage. The target saline aquifer, which is located at the middle of the conceptual model, has a larger permeability of 0.3 × 10⁻¹³ m² (30 mD) and a larger porosity of 0.094. This can result in a large pore volume to storage large amount of supercritical CO₂ gas in the saline aquifer. The CO₂ injection well is located at the point (33,520 m, 1495 m), which is close to the center of the conceptual model and at the bottom of the target saline aquifer. The initial temperature, pressure and mean stress at the injection point are 47.38°C, 1.4765 × 10⁷ Pa, and 2.40 × 10⁷ Pa respectively. The injection well is located the area which can keep CO₂ gas in a supercritical condition. The effective mean stress is 0.9235 × 10⁷ Pa. For the second case, there are five different domains with five different rock properties, including upper caprock, middle caprock, fault, target saline aquifer, and lower bedrock in Fig. 7. The fault is introduced by a stress weakness zone as domain 5 in Fig. 7, which is created into the middle caprock by means of a vertical fault zone. It is located between (33,580 m, 1200 m) and (33,580 m, 1300 m) with a horizontal width of 100 m and vertical length of 100 m. The initial permeability of the fault is set to be the same as the surrounding middle caprock, and it is set to be more porous with a larger porosity of 0.05. The relationships of porosity-stress and permeability-stress are more sensitive. The hydrological and stress-related parameters for each domain are listed in Table 2.

The injection rate of supercritical CO₂ is kept constant at 0.05 kg/s. The supercritical CO₂ is keeping injected for 30 years in the both cases of the conceptual model. The aquifer pressure will increase significantly with time increasing, under such an injection rate. In the previous study (Rutqvist and Tsang, 2002), the supercritical CO₂ continues to be injected into the target saline aquifer till the pore pressure becomes bigger than the lithostatic stress of the target saline aquifer after about 10 years’ injection. The geomechanical behavior needs to be investigated when a risk is identified to trigger fractures due to CO₂ injection. In the study, it intends to study not only the geomechanical behavior due to supercritical CO₂ injection for a short period, but also the geochemical behavior due to CO₂ storage for a long term. Therefore, the horizontal length of the conceptual model provides the supercritical CO₂ enough space to spread into the target aquifer due to 30 years’ injection without the potential to induce a fracture.

The isotropic geomechanical rock properties are represented by functions of porosity and mean stress, permeability and porosity. The functions They are given by Eqs. (23) and (28). The function of the capillary pressure scaling is given by Eq. (29). It is a scaling of the van Genuchten air-entry pressure from the values at zero stress to an initial in-situ air-entry pressure given in Table 2.

In the two cases designed for the conceptual model, there are four rock domains in the first case with different values of porosity, permeability and stress-related parameters, and there are five rock domains in the second case with different values of porosity, permeability and stress-related parameters. Therefore, the heterogeneous simulation domains for geomechanical calculation are presented in the two cases of the conceptual model. Based on the number of the equations to be solved in this conceptual model, and the potential convergence problem may occur when additional geochemical heterogeneity for different domains are taken into account in the conceptual model. It is assumed that the model is a homogeneous reservoir in terms of rock compositions, which means all the five domains have the same mineral compositions. Furthermore, a generalized rock mineral composition is assigned to all the simulation domains. The initial mineral abundances are shown in Table 3. The rock minerals selected in this conceptual

<table>
<thead>
<tr>
<th>Direction</th>
<th>Number of grid cell</th>
<th>Length(m)</th>
</tr>
</thead>
<tbody>
<tr>
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</tr>
<tr>
<td>x</td>
<td>10</td>
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<td>20</td>
</tr>
<tr>
<td>z</td>
<td>10</td>
<td>40</td>
</tr>
<tr>
<td>z</td>
<td>20</td>
<td>45</td>
</tr>
</tbody>
</table>
Fig. 6. Conceptual model profile along the vertical section with four different simulation domains.

Fig. 7. Conceptual model profile along the vertical section with five different simulation domains.
model is commonly encountered in the potential saline aquifers at North America, such as Gulf Coast sediments, Paradox basin in Colorado plateau. The initial concentrations of primary chemical species are under equilibrium condition with the rock minerals in the saline aquifer. The initial total concentrations of primary chemical species are given in Table 4. Among the saline aquifer. The initial total concentrations of primary chemical species are under equilibrium condition with the rock minerals in North America, such as Gulf Coast sediments, Paradox basin in model is commonly encountered in the potential saline aquifers at

4.2. Hydrological effects and mechanical effects: structural trapping

Fig. 8 presents the saturation contour profile of supercritical CO2 gas for 30 years’ CO2 injection. Fig. 8 (a) indicates that the supercritical CO2 gas starts to transport from the injection point (33,520 m, 1495 m) to the bottom of the caprock after 1 year’s injection period, with a horizontal distance of 400 m for the spread. The plume of supercritical CO2 is not formed yet at this period. The shape of the supercritical CO2 gas phase in the saline aquifer is like a wick of a lighted candle. The supercritical CO2 gas saturation is decreasing gradually from the inward to the outward of the wick. The largest CO2 gas saturation in the target saline aquifer is 0.45 in the middle (Fig. 8 (a)). After 3 years, the plume of supercritical CO2 gas is being formed gradually, and majority of the supercritical CO2 gas tends to accumulate below the bottom of the middle caprock due to low permeability (1 × 10⁻¹³ m²). The plume of the supercritical CO2 gas has a maximum diameter of 1400 m under the bottom of the middle caprock. The intrinsic permeability of the middle caprock in the conceptual model is larger than the one used in the previous model, therefore the supercritical CO2 gas phase may penetrate into the middle caprock. The supercritical CO2 gas penetrates into the middle caprock about 20 m after 3 years CO2 injection (Fig. 8 (b)). The maximum supercritical CO2 gas saturation is about 0.6 at the injection point of the target saline aquifer, and the diameter of the CO2 plume gradually increases from the bottom to the top of the saline aquifer. The supercritical CO2 gas tends to transport upwards rapidly, because the low density and viscosity of CO2 results in strong buoyant flow. Then, the plume continues to enlarge within 5 years’ CO2 injection (Fig. 8 (c)). The maximum diameter is 2300 m under the middle caprock, and the maximum CO2 saturation is about 0.7 around the injection point. The gas saturation is about 0.6 under the bottom edge of the middle caprock, which means that the majority of the CO2 gas accumulates under the middle caprock. The supercritical CO2 gas penetrates into the middle caprock about 40 m after 5 years’ injection (Fig. 8 (c)). At 10 years, the plume of CO2 is under the middle caprock over 4600 m and penetrates into the caprock by about 80 m (Fig. 8 (d)). The maximum saturation is about 0.85 around the injection point in the target saline aquifer. The supercritical CO2 gas saturation tends to be about 0.65 under the bottom edge of the middle caprock, which means that the majority of the CO2 gas accumulates under the middle caprock. The supercritical CO2 gas continues to transport upwards into the middle caprock domain. Furthermore, the supercritical CO2 keeps injected for 20 years (Fig. 8 (e)), and the supercritical CO2 has spread under the middle caprock over 8400 m, penetrated through the caprock, and escaped to the upper caprock domain above 10 m. The maximum CO2 saturation is about 1.0 around the injection point in the target saline aquifer, and the supercritical CO2 gas saturation tends to be about 0.75 under the bottom edge of the middle caprock. After 30 years, the spread of CO2 has become a big mushroom under the middle caprock over

Table 2

<table>
<thead>
<tr>
<th>Domain number</th>
<th>1</th>
<th>2</th>
<th>3</th>
<th>4</th>
<th>5</th>
</tr>
</thead>
<tbody>
<tr>
<td>Young’s modulus, E (Pa)</td>
<td>5 × 10⁹</td>
<td>5 × 10⁹</td>
<td>5 × 10⁹</td>
<td>5 × 10⁹</td>
<td>2.5 × 10⁹</td>
</tr>
<tr>
<td>Poisson’s ratio, ν</td>
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<td>0.25</td>
<td>0.25</td>
<td>0.25</td>
<td>0.25</td>
</tr>
<tr>
<td>Biot’s parameter, α</td>
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<td>1</td>
<td>1</td>
<td>1</td>
<td>1</td>
</tr>
<tr>
<td>Rock density, ρ (kg/m³)</td>
<td>2260</td>
<td>2260</td>
<td>2260</td>
<td>2260</td>
<td>2260</td>
</tr>
<tr>
<td>Zero stress porosity, φ₀</td>
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<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
<td>0.1</td>
</tr>
<tr>
<td>Residual porosity, φ_r</td>
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<td>0.09</td>
<td>0.09</td>
<td>0.09</td>
<td>0.09</td>
</tr>
<tr>
<td>Original porosity, φ</td>
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<td>0.094</td>
<td>0.094</td>
<td>0.094</td>
<td>0.094</td>
</tr>
<tr>
<td>Zero stress permeability, k₀ (m²)</td>
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<td>1 × 10⁻¹⁷</td>
<td>1 × 10⁻¹³</td>
<td>1 × 10⁻¹³</td>
<td>1 × 10⁻¹³</td>
</tr>
<tr>
<td>Original permeability, k (m²)</td>
<td>0.3 × 10⁻¹⁵</td>
<td>0.3 × 10⁻¹⁷</td>
<td>0.3 × 10⁻¹³</td>
<td>0.3 × 10⁻¹³</td>
<td>0.3 × 10⁻¹³</td>
</tr>
<tr>
<td>Corey’s irreducible gas saturation, S₀</td>
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<td>0.05</td>
<td>0.05</td>
<td>0.05</td>
<td>0.05</td>
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<tr>
<td>Corey’s irreducible liquid saturation, S_l</td>
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<td>0.3</td>
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<td>0.3</td>
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<tr>
<td>van Genuchten’s air-entry pressure, Pₑ (Pa)</td>
<td>1.96 × 10⁵</td>
<td>3.1 × 10⁶</td>
<td>1.96 × 10⁶</td>
<td>3.1 × 10⁶</td>
<td>1 × 10³</td>
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<tr>
<td>van Genuchten’s exponent, m</td>
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<td>0.457</td>
<td>0.457</td>
<td>0.457</td>
<td>0.457</td>
</tr>
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</table>

Table 3

<table>
<thead>
<tr>
<th>Table 3</th>
<th>Initial volume fractions of primary minerals in the model and potential secondary minerals.</th>
</tr>
</thead>
<tbody>
<tr>
<td>Mineral</td>
<td>Chemical compositions</td>
</tr>
<tr>
<td>---------</td>
<td>-------------------------</td>
</tr>
<tr>
<td>Primary mineral</td>
<td></td>
</tr>
<tr>
<td>Quartz</td>
<td>SiO₂</td>
</tr>
<tr>
<td>Calcite</td>
<td>CaCO₃</td>
</tr>
<tr>
<td>Oligoclase</td>
<td>CaNa₂Al₆Si₂₄O₆₀</td>
</tr>
<tr>
<td>Smectite-Na</td>
<td>Na₂₂₋₉Mg₂₋₀₉Al₁₋₉Si₃₋₀₉O₉₀(OH)₁₂⁻</td>
</tr>
<tr>
<td>Chlorite</td>
<td>Mg₅₋₁₋₇Fe₂₋₇Al₇₋₇Si₇₋₇O₉₀(OH)₁₉⁻</td>
</tr>
<tr>
<td>Kaolinite</td>
<td>Al₂Si₇O₁₉(OH)₃⁻</td>
</tr>
<tr>
<td>K-feldspar</td>
<td>KAl₃Si₃O₁₀⁻</td>
</tr>
<tr>
<td>Secondary mineral</td>
<td></td>
</tr>
<tr>
<td>Magnesite</td>
<td>MgCO₃</td>
</tr>
<tr>
<td>Low-albite</td>
<td>NaAlSi₃O₈⁻</td>
</tr>
<tr>
<td>Siderite</td>
<td>FeCO₃</td>
</tr>
<tr>
<td>Ankerite</td>
<td>CaMg₂(Fe₂₋₇Al₇₋₇Si₇₋₇O₉₀(OH)₁₉⁻</td>
</tr>
<tr>
<td>Dawsonite</td>
<td>NaAlCO₃(OH)₃⁻</td>
</tr>
<tr>
<td>Smectite-Ca</td>
<td>Ca₀.₁₄₅Mg₀.₉₆₅Al₁₋₇Si₉₋₇O₇₋₀(OH)₁₂⁻</td>
</tr>
<tr>
<td>Total</td>
<td></td>
</tr>
</tbody>
</table>

Please cite this article in press as: Zhang, R., et al., Sequentially coupled THMC model for CO2 geological sequestration into a 2D heterogeneous saline aquifer, Journal of Natural Gas Science and Engineering (2015), http://dx.doi.org/10.1016/j.jngse.2015.09.013
The shape of the whole CO₂ gas saturated area is like a flatter. With CO₂ injection, the pressure increases in the target aquifer and caprock for 30 years’ CO₂ injection. After 3 years’ CO₂ injection, the plume of supercritical CO₂ gas in the target saline aquifer, Journal of Natural Gas Science and Engineering (2015), http://dx.doi.org/10.1016/j.jngse.2015.09.013

Table 5
Kinetic parameters for mineral dissolution and precipitation (Xu et al., 2004c).

<table>
<thead>
<tr>
<th>Mineral</th>
<th>( A ) (( \text{cm}^2/\text{g} ))</th>
<th>Parameters for kinetic rate law</th>
<th>Acid mechanism</th>
<th>Base mechanism</th>
</tr>
</thead>
<tbody>
<tr>
<td>Quartz</td>
<td>9.8</td>
<td>( K_{25} ) (mol/m² s), ( E_a ) (kJ/mol)</td>
<td>( K_{25} ), ( E_a ), n(H⁺)</td>
<td>( K_{25} ), ( E_a ), n(H⁺)</td>
</tr>
<tr>
<td>Kaolinite</td>
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12,400 m and has transported upwards into the upper caprock by 50 m (Fig. 8(f)). The maximum CO₂ saturation is about 1.0 around the injection point in the target saline aquifer, and the supercritical CO₂ gas saturation tends to be about 0.8 under the bottom edge of the middle caprock. Finally, Fig. 9 shows the plume of the CO₂ in the target aquifer and caprock for six injection periods. The stability and integrity of the caprock plays a key role as a barrier of CO₂ injection. After 3 years’ CO₂ injection, the plume of supercritical CO₂ gas penetrates through the fault, and transports into the target aquifer and caprock for 30 years’ CO₂ injection.

Figs. 12 and 13 show the contour of pore pressure, mean stress and volumetric strain in the vertical direction for both Case 1 without fault and Case 2 with fault at 10 years. Based on the iso-pressure and iso-tress curves, the mean effective stress can be calculated. The simulation results indicate that the significant increase in pore pressure leads to the decrease of the mean effective stresses in the caprock and aquifer. The largest changes of effective stress happen at the bottom of the caprock and top of the bedrock. At the injection point, the mean effective stress has decreased by 5.6 \times 10^6 Pa after 10 years’ CO₂ injection. The change of effective stress is less than that of the pore pressure, because CO₂ injection increases the mean stress. Fig. 12 shows the simulated results for Case 1 without fault after 10 years’ CO₂ injection. The pressure propagates mainly along the bottom of caprock. The pressure, the mean stress, and volumetric strain peak at the injection point and propagate into the surrounding, but do not break through the caprock before 10 years. After this, the pressure, the mean stress, and volumetric strain start to break through the middle caprock into upper caprock with the continuous CO₂ injection till 30 years. Fig. 13 shows the simulated results for Case 2 with fault after 10 years’ CO₂ injection, pressure, the mean stress and volumetric strain reach the maximum value at the injection site, and then propagate to the surrounding, and more importantly, the changes are along both the bottom of middle caprock and the fault. Comparing the changes of ground uplift and pressure at the injection site with time for both cases, it is indicated that the existing of fault cause much more changes of pore pressure and much bigger ground uplift.

The changes of the mean stresses in the layered formation leads to a vertical expansion of the rock. The increases of the pore pressure changes mean stress and volumetric strain. The uplift of the formation can be calculated from volumetric strain changes by summation over z direction grid block columns and the assumption of strain isotropy. The uplifts of the formation surface are shown in Figs. 14 and 15 for Case 1 without fault and Fig. 15 for Case 2 with fault. The expansion of formation occurs not only in the aquifer but also in the caprock because of the fault. The uplift in Case 2 shall be greater than in Case 1. Fig. 15 indicates that the maximum uplift is about 1.8 m for the layered formation without fault after 30 years’ CO₂ injection.

4.3. Permeability and porosity change by mechanical effects

Figs. 16 and 17 show the pressure-induced permeability change and porosity change for Case 1 during 30 years’ CO₂ injection period. The permeability change in the formation is proportional to the pressure and stress increase, and the porosity change is proportional to permeability change. The largest changes in permeability occurs in the top boundary of the aquifer. The permeability ratio is the ratio between the pressure induced permeability and intrinsic permeability, and the porosity ratio is the ratio between the pressure induced porosity and original porosity. The permeability has increased by a factor of about 3.3 near the top boundary of the aquifer. Correspondingly, and the porosity has increased by a factor of about 1.06 near the top boundary of the aquifer. Figs. 18 and 19 show the pressure-induced permeability change and porosity change for Case 2 during 30 years’ CO₂ injection period. The two figures only show the permeability and porosity change in the fault. Both the length and width of fault are 100 m. The
permeability and porosity ration are displayed within the range of 100 m. The stress weakness is induced with the fault, which causes the mean stress increase significantly. This phenomenon can be observed from the mean stress profile in Figs. 12 and 13. The permeability is proportional to the effective mean stress. Therefore, the permeability change in the fault domain is significant. The

Fig. 8. Saturation contour profile of the supercritical CO₂ gas in the target saline aquifer for Case 1 during 30 years’ injection period: (a) 1 year, (b) 3 years, (c) 5 years, (d) 10 years, (e) 20 years and (f) 30 years.
permeability has increased by a factor of 325 and the porosity has increased by a factor of about 1.84.

4.4. Phase equilibrium and chemical equilibrium: solubility trapping

Within a long term storage time, the dissolved CO$_2$ in aqueous phase is consumed by the geochemical reaction between aquifer water and rock mineral, especially for the dissolution/precipitation of the carbonate minerals. The aqueous CO$_2$ continues to be consumed in aqueous phase, and the CO$_2$ gas phase continues to be dissolved into aqueous phase. The CO$_2$ gas saturation continues to decrease in the area of two phase mixture. The area near wellbore is occupied by two phase mixture. Fig. 20 shows the spatial distribution of CO$_2$ gas saturation during 10,000 years’ storage period. Majority of the CO$_2$ gas accumulates under the middle caprock, which can be observed from Fig. 20 (a–c). After 5000 years, majority of the supercritical CO$_2$ gas escapes the barrier of middle caprock, and penetrates into the upper caprock, which can be observed from Fig. 20 (d–f). The CO$_2$ gas is accumulates in the area with a width of 30,000 m and a length of 300 m. The amount of CO$_2$ gas starts to decrease and some of CO$_2$ gas continues to move upwards at the same time. After 10,000 years, the CO$_2$ gas saturation decrease to 0.1 because of the chemical reaction.

Dissolution of the free phase CO$_2$ in aquifer water is caused by the geochemical reaction between water and CO$_2$. This chemical reaction is believed as the fastest reaction and always set as equilibrium condition. It generates the aqueous chemical species of H$_2$CO$_3$, HCO$_3^-$, and CO$_2^{\text{aq}}$. The chemical species H$^+$ acidizes the aqueous environment and decreases the pH value in the saline aquifer. After the dissolution of free phase CO$_2$, the two phase mixture area become acidized region, where the pH is less than 7.0. Fig. 21 shows the spatial distribution of pH value during the 10,000 years’ CO$_2$ storage period. The pH value in the plume of CO$_2$ gas is 4.8 after 30 years’ CO$_2$ injection in Fig. 21 (a). The acidized area by CO$_2$ dissolution continues to spread with CO$_2$ moving upwards during CO$_2$ storage period. After 5000 years, some of the CO$_2$ gas has already been consumed under the middle caprock. The pH value in the area under the middle caprock is above 7.0 and become alkalized, which is obvious in Fig. 21 (d–f).

4.5. Mineral dissolution and precipitation: mineral trapping

There are seven primary rock minerals and six secondary minerals present in this numerical model. The formation type is sandstone, which is always composed of large amount of quartz, small amount of carbonate minerals, plagioclase feldspar minerals and clay minerals, and minor components. For the geochemical composition in this model, the most common minerals in the potential CO$_2$ sequestration site from the literature are taken into account. Calcite represents the carbonate minerals. Oligoclase represents the plagioclase feldspar minerals. Chlorite represents the clay minerals. The volume fraction change profiles of the primary and secondary minerals during 3000 years are illustrated in Figs. 22–29.

Dissolution and precipitation of primary minerals: it is obvious to observe the dissolutions of oligoclase, chlorite and calcite in the order of magnitude, and the precipitation of smectite and quartz. Figs. 22–26 show the volume fraction evolution of these rock minerals during 10,000 years’ storage period. The dissolution happens in two areas in saline aquifer and in upper caprock. The reactivity in the middle caprock is not significant due to the small porosity and permeability of the middle caprock. Fig. 22 shows the dissolution of the oligoclase during the storage period. The maximum volume fraction decrease of oligoclase is 1.15 percent after 500 years (Fig. 22 (a)), 1.95 percent after 1000 years (Fig. 22 (b)), 2.90 percent after 3000 years (Fig. 22 (c)), and 3.95 percent after 5000 years (Fig. 22 (d)), 5.35 percent after 8000 years (Fig. 22 (e)) and 7.45 percent after 10,000 years (Fig. 22 (f)). The dissolution of oligoclase releases large amounts of chemical species (Ca$^{2+}$, SiO$_2$($aq$), AlO$_2^-$ and Na$^+$), which supply the chemical species to precipitate albite (NaAlSi$_3$O$_8$), dawsonite (NaAlCO$_3$(OH)$_2$), and smectite-Na (Na$_{0.29}$Mg$_{0.26}$Al$_{1.77}$Si$_{3.97}$O$_{10}$(OH)$_2$). Fig. 23 shows the dissolution of the chlorite during the storage period. The maximum volume fraction decrease of chlorite is less than 0.1 percent after 500 years (Fig. 23 (a)), 0.62 percent after 1000 years (Fig. 23 (b)), 0.82 percent after 3000 years (Fig. 23 (c)), and 1.12 percent after 5000 years (Fig. 23 (d)), 1.72 percent after 8000 years (Fig. 23 (e)), and 2.12 percent after 10,000 years (Fig. 23 (f)). The dissolution of chlorite releases large amounts of chemical species (Fe$^{2+}$, Mg$^{2+}$, SiO$_2$($aq$), and AlO$_2^-$), which supply the chemical species to precipitate siderite (FeCO$_3$) and ankerite (CaMg$_{0.3}$Fe$_{0.7}$(CO$_3$)$_2$).

Fig. 24 shows the dissolution and precipitation of calcite during the long storage period. It is dissolved in the acidized area and precipitated in the alkalized area under the middle caprock. The volume fraction change of calcite reaches the maximum amounts till 10,000 years (Fig. 24 (e)). The maximum volume fraction increase of calcite is 0.5 percent in the alkalized zone, and the maximum volume fraction decrease is 0.8 percent at the acidized zone. Because the abundance of the chemical species of Mg$^{2+}$, SiO$_2$($aq$), AlO$_2^-$ and Na$^+$ released by the dissolutions of oligoclase and chlorite, the smectite is precipitated into rock minerals. Fig. 25 shows the precipitation of smectite-Na during the storage period. The maximum volume fraction increase of smectite-Na is 0.52 percent after 500 years (Fig. 25 (a)), 1.70 percent after 1000 years (Fig. 25 (b)), 2.20 percent after 3000 years (Fig. 25 (c)), and 3.75 percent after 5000 years (Fig. 25 (d)), 5.20 percent after 8000 years (Fig. 25 (e)), and 6.70 percent after 10,000 years (Fig. 25 (f)). Fig. 26 shows the precipitation of quartz during the storage period. Quartz is precipitated with the largest amount in the acidized area under middle caprock during the total storage period of 10,000 years (Fig. 26). The dissolution of primary rock minerals releases large amounts of SiO$_2$($aq$), which make the chemical species SiO$_2$($aq$) supersaturated in the aquifer water, then precipitated into the rock. Quartz continues to precipitate into the mineral phase during 10,000 years’ storage time, and the maximum amount of volume...
fraction increase is 1.0 percent (Fig. 26(f)).

Precipitation of secondary minerals: the order of volume fraction increase for secondary minerals are albite, ankerite and dawsonite. Majority of the potential secondary minerals are carbonate minerals except for albite. The precipitation of the secondary rock minerals mainly happens in aquifer and the upper caprock.
minerals) in the saline aquifer are shown in Fig. 30. As time increasing, the mass of CO₂ permanently trapped in mineral phase increases continuously in the acidized area and reaches the maximum amounts in the aquifer and upper caprock due to precipitation of the secondary silicate and carbonate minerals, such as ankerite, dawsonite and albite. The maximum amount of CO₂ stored by mineral trapping is about 20.0 kg/m³ rock after 10,000 years (Fig. 30(d)).

It is indicated that the precipitated new minerals are mainly in the CO₂ plume of target aquifer and in the upper caprock. The mineral trapping of CO₂ is not significant in the middle caprock compared with the saline aquifer and upper caprock. The permeability and porosity of middle caprock is 0.3 × 10⁻¹⁷ and 0.0094, there is only a small amount of saline water saturated in the middle caprock and CO₂ gas trapped in the pore space. The possibility of chemical reactions is reduced due to the small permeability and porosity. In addition, the CO₂ migrates into upper caprock during long term storage period. The mineralogical composition of the upper rock determines the long term fate of supercritical CO₂ in subsurface. It is obvious that the mineralization of CO₂ gas occurs at the bottom of the upper caprock.

Fig. 31 indicates the temporal changes of the mass fraction of CO₂ trapped by the three mechanisms: structural trapping, solubility trapping and mineral trapping. The fraction of structural trapping starts at 81.7 percent at the beginning of storage period, and then decreases gradually to 54.96 percent after the chemical reaction become dominant with time increasing. The fraction of solubility trapping starts at the maximum 18.34 percent at the beginning of the storage time. The pressure rises up rapidly during the 30 years injection period, then the partial pressure of CO₂ in the aqueous phase increases accordingly, which drives more CO₂ dissolve into the aqueous phase. When the injection stops, long term storage period begins and pressure buildup releases rapidly. The total pressure around the injection area starts to decrease, thus the CO₂ partial pressure decreases successively. A small amount of dissolved CO₂ is released into the gaseous phase again, and a certain amount of dissolved CO₂ is consumed by the mineralization, the contribution of solubility trapping decreases to 9.98 percent till 10,000 years. Finally, the mineral trapping become dominant in the long term storage time, which is shown in the black line of 31. In particular, the fraction of mineral trapping increases slowly at the first 100 years’ storage period, and then it is increasing rapidly till 10,000 years. At the beginning of the storage time, various chemical species (i.e., Fe²⁺, Mg²⁺, Ca²⁺, etc.) release into the aqueous phase, the previous established chemical equilibrium state is broke. Alternations of rock minerals become dominated after these chemical species become supersaturated in the aqueous phase. A new stable state is achieved when the supply of aqueous CO₂ is sufficient for the kinetic reactions in the acidized area, then the fraction of mineral trapping increases stably to 35 percent. In the previous literature, the researcher has presented a general sketch of the evolution of trapping mechanisms over time (IPCC 2005). Fig. 31 gives a quantitative view of the contribution of the three mechanisms. The area under the black line represents the contribution of mineral trapping, the middle area between the black and red lines is the contribution of solubility trapping, and the top area is the contribution of structural and residual trapping. It is indicated that the chemical reaction is the most dominated trapping mechanism in the long term storage period.

4.7. Effects of oligoclase and chlorite presences on mineral trapping

We investigate the effects of volume fraction changes of oligoclase and chlorite on the mineral trapping of CO₂. Based on the mineral compositions in the model, three additional cases are run
to study the sensitivity of oligoclase fraction. The volume fraction of oligoclase is increased by 5 percent in each case, and the volume fraction of quartz is decreased by 5 percent. The sensitivity study of chlorite has the same scenario with oligoclase. The temporal changes of the CO2 trapped by the mineralization in terms of the volume fraction changes of oligoclase and chlorite are shown in Figs. 32 and 33. Fig. 32 shows that the contribution of mineral trapping increases to 53.21 percent due to the abundance of

Fig. 12. Pressure, mean stress and volumetric strain contour profile for Case 1 after 10 years’ injection period: (a) pressure contour; (b) iso-pressure line; (c) mean stress contour; (d) iso-stress line; (e) strain contour; (f) iso-strain line.

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oligoclase (25.66%). When the volume fraction of oligoclase increases by 5 percent, the contribution of mineral trapping increases by about 6 percent. Because of sufficient Na\(^+\), SiO\(_2\)\(_{aq}\), and AlO\(_2\)

releasing in to aqueous phase at the late of storage period, the gaseous CO\(_2\) continues to be trapped by the alternation of rock minerals. Fig. 33 shows that the contribution of mineral trapping
an important role for trapping free phase CO\textsubscript{2} in saline aquifer. The volume fractions of oligoclase and rock mineral compositions play an important role for trapping free phase CO\textsubscript{2} in saline aquifer. The volume fractions of oligoclase and chlorite present in the rock have significant impact on the trapping contribution of the three mechanisms.

5. **Concluding marks**

The significance of THMC process interactions during CO\textsubscript{2} geo-sequestration has been well recognized in the perspectives of field scale and pore scale. Chemical reaction is the most complex process among the THMC processes. The rock minerals, which play a major key role in the trapping mechanisms, are identified. A novel mathematical model of the THMCS model is developed. A computational framework, sequentially coupled, is proposed and used to simulate reactive transport of supercritical CO\textsubscript{2} in subsurface formation with geo-mechanics. The novel frameworks are designed to keep a generalized computational structure, which can be easily applied for the numerical simulation of other THMC processes. Finally, a 2D reactive transport model is presented to analyze the THMC processes quantitatively, especially the coupled effects of geo-chemical reactions and geo-mechanics on CO\textsubscript{2} geo-sequestration, the long term fate of CO\textsubscript{2} and its sensitivity mineralogical compositions with respect to key minerals. The numerical simulation results have indicated that:

- For the formation with heterogeneous domains (upper caprock, middle caprock, saline aquifer and lower bedrock), pore pressure and mean stress increase significantly under the middle caprock, that may lead to rock failure. The upward migration of supercritical CO\textsubscript{2} speeds up through permeable faults, created by geomechanical permeability and porosity increase. The mineral trapping of supercritical CO\textsubscript{2} mainly occurs in upper caprock saline aquifer. The possibility of chemical reaction is reduced due to the small permeability and porosity of middle caprock and the small amounts of saturated water in middle caprock.

- Important geochemical reactions leading to favorable mineral trapping of CO\textsubscript{2} include dissolution of plagioclase feldspar and chlorite minerals, which release large amounts of chemical species Fe\textsuperscript{2+}, Mg\textsuperscript{2+}, Na\textsuperscript{+}, AlO\textsubscript{2} and SiO\textsubscript{2}(aq), the precipitations of carbonate and silicate minerals, such as dawsonite, albite and ankerite, which combine metal ions with bicarbonate together to consume more supercritical CO\textsubscript{2} gas. The long term fate of supercritical CO\textsubscript{2} under the subsurface is to be sequestrated in the rock mineral permanently in the forms of carbonate minerals.

- In terms of the efficacy for the trapping mechanisms, structural trapping is the dominated mechanism during supercritical CO\textsubscript{2} injection period, and mineral trapping dominates during long term storage period. In a typical sandstone formation, with 60 percent quartz, 20 percent plagioclase feldspar minerals, 10 percent chlorite minerals, and 10 percent clay minerals, the efficacy of solubility trapping is 18.34 percent at the early injection period, which decreases to 9.98 percent after 10,000 years; the efficacy of mineral trapping is zero percent at early injection period, which increases to 35 percent after 10,000 years.

- Rock mineral compositions of the potential formation of CO\textsubscript{2} geo-sequestration play a significant role on the geochemical behavior of supercritical CO\textsubscript{2}, trapping mechanism and their efficacies. Oligoclase and chlorite are two key rock minerals as representatives of plagioclase feldspar minerals and chlorite minerals, which are the common rock forming minerals in sandstone. The efficacies of mineral trapping increases with the increasing volume fractions of oligoclase and chlorite. In sandstone aquifer, the efficacy of mineral trapping increases by 5 percent when the volume fraction of oligoclase increases by 5 percent. The contribution of mineral trapping increases to 53.21 percent due to the abundance of oligoclase (25.662%). When the volume fraction of chlorite increases by 5 percent, the contribution of mineral trapping increases by about 3 percent. The contribution of mineral trapping increases to 45.53 percent due to the abundance of chlorite (25.031%).

- The limitations of this simulator are as follows: it does not have the capability to simulation non-aqueous chemical reactions, i.e. the geochemical reactions between supercritical CO\textsubscript{2} and rock minerals. It does not have the capability to solve the shear stress,
since a simplified mean stress equation is taken in account in this paper. Vertical displacement can be obtained as the results of the mean stress calculation. Stress failure cannot be predicted. Furthermore, it may require much more runtime for a certain simulation case, since the chemical reaction is coupled together with geomechanics in the same simulator.

Fig. 16. Permeability change ratio profile for Case 1 after 30 years' injection period: (a) 1 year; (b) 3 years; (c) 5 years; (d) 10 years; (e) 20 years; (f) 30 years.
Fig. 17. Porosity change ratio profile for Case 1 after 30 years' injection period: (a) 1 year; (b) 3 years; (c) 5 years; (d) 10 years; (e) 20 years; (f) 30 years.
Fig. 18. Permeability change ratio profile for Case 2 after 30 years' injection period: (a) 1 year; (b) 3 years; (c) 5 years; (d) 10 years; (e) 20 years; (f) 30 years.
Fig. 19. Porosity change ratio profile for Case 2 after 30 years' injection period: (a) 1 year; (b) 3 years; (c) 5 years; (d) 10 years; (e) 20 years; (f) 30 years.
Fig. 20. CO₂ gas saturation profile during 10,000 years’ storage period: (a) 100 years; (b) 500 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 21. The pH value profile during 10,000 years' storage period: (a) 30 years; (b) 500 years; (c) 1000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 22. The volume fraction change of oligoclase during 10,000 years' storage period: (a) 500 years; (b) 1000 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 23. The volume fraction change of chlorite during 10,000 years’ storage period: (a) 500 years; (b) 1000 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 24. The volume fraction change of calcite during 10,000 years' storage period: (a) 30 years; (b) 1000 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 25. The volume fraction change of smectite-Na during 10,000 years’ storage period: (a) 500 years; (b) 1000 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 26. The volume fraction change of quartz during 10,000 years’ storage period: (a) 500 years; (b) 1000 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 27. The volume fraction change of albite during 10,000 years' storage period: (a) 500 years; (b) 1000 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 28. The volume fraction change of ankerite during 10,000 years' storage period: (a) 500 years; (b) 1000 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 29. The volume fraction change of dawsonite during 10,000 years' storage period: (a) 500 years; (b) 1000 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 30. The amount of CO₂ sequestered in rock mineral during 10,000 years' storage period: (a) 500 year; (b) 1000 years; (c) 3000 years; (d) 5000 years; (e) 8000 years; (f) 10,000 years.
Fig. 31. Trapping contribution of CO₂(gas) during 10,000 years’ CO₂ storage period.

Fig. 32. Mineral trapping contribution of CO₂(gas) relative to the volume fraction of olivoclase during 10,000 years’ CO₂ storage period.

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