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Development of a Multi-Continuum Multi-Component Model for Enhanced Gas Recovery and CO_2 Storage in Fractured Shale Gas Reservoirs

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Abstract

Shale gas reservoirs have been proposed as feasible choices of location for injection of CO_2 and/or N_2 because this method could enhance recovery of natural gas resources, while at the same time sequester CO_2 underground. In this paper, a fully coupled multi-continuum multi-component simulator which incorporates several transport/storage mechanisms is developed. To accurately capture physics behind the transport process in shale nanopores, Kundsen diffusion and gas slippage are included in the flow model. An extended Langmuir isotherm is used to describe the adsorption/desorption behavior of different gas components and the displacement process of methane as free gas. Pressure-dependent permeability (due to rock deformation) of natural fractures induced by hydraulic fracturing is also considered in the simulator.

In addition, modeling of complex fracture networks is very crucial for simulating production of shale gas reservoirs because there exists various scales of fractures with multiple orientations after the fracturing treatment for horizontal well. In this work, a hierarchical approach which integrates EDFM with dual-continuum concept is adopted. The hybrid model includes three domains: matrix, major hydraulic fractures and large-scale natural fractures (described by EDFM), and micro-fractures in SRV region which are modeled by dual-continuum approach. Embedded Discrete Fractures Model (EDFM) is an efficient approach for explicitly simulating large-scale fractures in Cartesian grid instead of complicated unstructured grid. Moreover, a nested-grid refinement method is used to capture the fluids transfer from matrix to fractures.

Fully implicit scheme is applied for discretizing fluid equations, and the corresponding Jacobian matrix is evaluated by Automatic Differentiation with Expression Templates Library (ADETL). The AD-Library framework allows wide flexibility in the choice of variable sets and provides generic representations of discretized expressions for gridblocks. Several simulations and sensitivity analysis are performed with the developed research code for determining the key factors affecting shale gas recovery. Modeling studies indicate that the properties of fracture networks could greatly influence methane production. Different injection strategies including huff-n-puff scenario are also evaluated to provide insights for optimizing production of multi-fractured horizontal well. Results show that CO_2/N_2 injection can be an effective approach with great application potential for enhancing shale gas recovery.

Introduction

There is recent interest in the utilization of shale gas reservoirs as promising targets for Enhanced Gas Recovery (EGR) processes; in EGR, CO_2 is injected to simultaneously enhance gas production while sequestering CO_2 underground. Methane is commonly stored in shale gas sediments as compressed gas in micro-fractures and pores, as adsorbed gas to the pore walls and surface of organic materials (Javadpour et al., 2007). Although a large amount of gas-in-place could come from adsorbed gas, limitations such as the ultra-low matrix permeability and relatively high BHP of wells may not allow them to be effectively produced (Cippola, 2010). Dahaghi (2010) demonstrated that injection of CO_2 into gas shale for EGR is feasible because of the greater sorption affinity for CO_2 than methane in organic-rich rock. Several simulation studies were also performed through in-house or commericial simulators to evaluate the applicability of CO_2 injection to expedite the desorption process in shale gas reservoirs, and to study the impacts of this method on ultimate gas recovery (Schepers et al., 2009; Hai Sun et al., 2013; Faye Liu et al., 2013). Carbon dioxide, nitrogen or a mixture of both gases could be chosen for EGR in gas shale. The injected nitrogen plays a role in lowering the partial pressure of methane, and CO_2 which is more strongly adsorbable than methane, could promote release and displacement of methane as free gas through an in-situ molecular swapping mechanism (S.M. Kang et al., 2011).

Javadpour et al. (2009) reported that gas flow in shale gas reservoirs cannot be described simply by Darcy's law because of the small pores that are at the scale of nanometers. Processes such as Knudsen diffusion and slip flow could be the dominant flow-type in the shale matrix. In order to accurately describe the storage and transport mechanism of gas flow during the CO_2-EGR process, we develop a novel multi-continuum model that incorporates the effects of slip flow and Knudsen diffusion in apparent permeability. Additionally, we incorporate extended Langmuir isotherms to simulate the multi-component sorption behavior. In addition, geomechanical effects could be relatively large and may have a substantial influence on the unpropped natural fractures that are induced by hydraulic fracturing. These have been shown to be important to consider in shale gas formations (Yushu Wu et al., 2013). Therefore, we also incorporate pressure-dependent permeability within the natural fractures network.

Due to the ultra-low matrix permeability, the economic development of shale gas reservoirs depends much on effective stimulation treatments through multi-stage hydraulic fracturing of horizontal wells. Accurate modeling of gas production is very challenging, because the reservoirs comprise complex fracture networks with multiple orientations, length and conductivity after hydraulic fracturing measures. Two classes of approaches are commonly used for describing fluid fow in fractured systems: 1) dual porosity/permeability 2) discrete fracture model (DFM).

The dual-porosity model proposed by Warren and Root (1963) is widely adopted in fractured reservoir simulations. It is suitable for reservoirs with highly connected, small-scale fractures. However, limitations are also presented that it is not applicable to model disconnected fractured media or a small number of large-scale fractures which may dominate the flow. Moinfar et al. (2011) demonstrated examples where the dual-porosity model fails to obtain satisfying solutions in the presence of fracture systems with high heterogeneity.

Compared to dual-continuum models, DFMs offer several advantages. They can be used to simulate realistic fracture system geometry, thereby accounting explicitly for the effect of individual fractures on fluid flow. Also the specificiation of the exchange between matrix and fracture is relatively straightforward since it depends directly on fracture geometry. Karimi-Fard et al. (2004) and Matthai et al. (2005) developed DFMs based on control-volume formulations, and employed unstructured grids to honor the geometry of fracture networks. However, the disadvantage of DFMs is that they cannot practically be used to simulate natural or micro fractures in general because of the associated prohibitive computational cost. Besides, the quality of the generated unstructured grids relies much on the mathematical algorithms applied, which could be very complicated for certain scenarios. S.H. Lee et al. (2001), Liyong Li et al. (2008), H. Hajibeygi et al. (2011) and Ali Moinfar et al. (2012) developed and improved the embedded discrete fracture models (EDFM) which incorporates the effect of each fracture explicitly, as well as offers computation-efficient simulations using Cartesian grids. EDFM introduces additional computational control-volumes for fractures through the interactions of fractures with matrix grids, and it is very flexible for handling various kinds of intersections such as frac-frac and frac-well (Liyong Li et al., 2008).

In spite of the recent advances in seismic technology, detailed characterization of pre-existing natural fractures in shale gas reservoirs is often unavailable because of economic considerations. Also, it is impractical to model large amount of fractures with DFM because of its inconvenience for automatic history matching problems. The inverse process could be very slow or lead to divergence results because suitable algorithms may be not available, and the amount of the parameters needed to be auto-matching is too large. Furthermore, correlation factors required by auto-maching techniques cannot be determined due to the complexity involved in fracture properties such as location, orientation, length and aperture (Parham Ghods et al., 2012). Therefore, it is more appropriate to model hydraulic fractures and large-scale natural fractures by DFM and employ dual-continuum approach for numerous natural fractures (Ali Moinfar et al., 2013).

In order to obtain the balance among accuracy, computational efficiency and field practice, we propose a multi-continuum method which integrates EDFM, dual-porosity and MINC (multiple interacting continua) concept for successfully simulating the production process of multi-fractured horizontal wells in shale gas reservoirs. The method developed could explicitly describe the dominant role of large-scale fractures as flow conduits, and simulate the natural fracture networks which connect the global flow in stimulated areas of shale gas reservoirs. Moreover, to better capture the transient fracture-matrix interaction caused by the extremely low matrix permeability, the MINC method (Pruess et al., 1985; Yushu Wu et al., 1988) which subdivides nested-grids inside matrix is applied. The traditional dual-porosity approach could result in large inaccuracy for the reason that it may take years to reach the pseudo-steady state in the matrix systems. With the developed multi-component simulator, we perform comprehensive simulation studies to determine the key factors of reservoir and fractures that affect the ultimate gas recovery in shale gas reservoirs. Different engineering factors and injection strategies are also analyzed and compared to provide guidance for production optimization during the CO_2-EGR process.

Physical Modeling of Flow and Transport

Although what we are most concerned with in shale gas reservoir simulations is to model gas flow from reservoir to well, liquid phase flow is often occurring simultaneously with gas flow because the existence of hydraulic fracturing fluids around well or gas condensate inside shale formation (Yushu Wu et al., 2013). To reduce the complication in simulation studies and clearly examine the influence of various factors on production performance, we apply the single-phase multi-component flow model in this work. The model assumes gas is stored in natural and primary fractures as free phase, while in matrix as both free and adsorbed phase. In an isothermal system containing n_c mass components, subject to gravity effect, non-darcy flow and adsorption, n_c mass-balance equations are needed to fully describe the system (matrix or fracture). The general governing equations considering various interactions between continuums:

$$\frac{\partial}{\partial t}\{\phi\rho_g x_i + (1-\phi)m_i\} = \nabla\cdot(\rho_g x_i v) + q_i^w + q_i^{conn} \tag{1}$$

Darcy's Law is used to describe the gas flow:

$$v = \frac{k}{\mu}(\nabla p - \gamma g \nabla D) \tag{2}$$

The mole of component i adsorbed in unit formation volume, (only for matrix):

$$m_i = \rho_R \rho_{gs} V_i \tag{3}$$

Where ϕ is the porosity of matrix or fractured media; k is the apparent permeability of matrix or pressure-dependent permeability of fractures; μ is the gas viscosity; γ is the mass density of gas mixture; ρ_g is the gas molar density; x_i is the component mole fraction; ρ_R is the rock bulk density; ρ_{gs} is the gas molar density at standard condition; V_i is the adsorption isotherm function; q_i^w is the source/sink term of component i; q_i^{conn} is the flux terms of component i between continuums.

Knudsen Diffusion and Slip Flow. The main differences between fluid mechanics in micropores (conventional reservoirs) and nanopores (shale gas reservoirs) can be calssified into two types: non-continuum effects and dominant surface interactive forces. These two effects cannot be neglected when the size of pores reaches nano-scale. Therefore, we apply the formulation derived by F. Javadpour (2009) to incorporate Knudsen diffusion and gas slippage effect in the flow model. If the pore sizes are obtained through measure techniques, absolute Darcy's permeability can be estimated for circular capillary using Hagen Poiseuille's equation (Vivek Swami et al., 2013):

$$k_D = \frac{r^2}{8} \tag{4}$$

Then the effective Darcy permeability for porous medium is:

$$k_m = \frac{\phi_m}{\tau} k_D \tag{5}$$

In the derivation given by F. Javadpour (2009), the total flux of gas flow through nanopore is the combination of advection due to pressure forces and Knudsen diffusion, and the advective term was corrected for accounting slip flow. Then the final expression for the apparent permeability of component i is (only considered in matrix):

$$k_{app} = \frac{\phi_m}{\tau}\left\{\frac{2r\mu}{3RT\rho_g}\left(\frac{8RT}{\pi M_i}\right)^{0.5} + \frac{r^2}{8}\left[1 + \frac{\mu}{pr}\left(\frac{2}{\alpha} - 1\right)\left(\frac{8\pi RT}{M_i}\right)^{0.5}\right]\right\} \tag{6}$$

Where r is the pore radius; R is the gas constant; T is the absolute temperature; M_i is the molar weight of component i; α is the tangential momentum accommodation coefficient, which depends on wall surface smoothness, gas type, temperature and pressure; τ is the tortuosity of porous medium.

Multi-Component Adsorption and Desorption. Because CO_2 is preferentially adsorbed over CH_4, the competitive gas adsorption will play a considerable role in CO_2-EOR process for shale gas reservoirs. An extended Langmuir isotherm which describes the fractional surface coverage of each component is used for describing the multi-component adsorption/desorption behavior. As shown in Eqn.(1), the molar quantity adsorbed can be considered in the accumulation term of governing equation. The standard volume of component i adsorbed per unit rock mass can be expressed as:

$$V_i = \frac{V_{L,i}(px_i) / P_{L,i}}{1 + \sum(px_i / P_{L,i})} \tag{7}$$

Where $V_{L,i}$ is the Langmuir volume of component i (the maximum adsorption capacity at a given temperature), and $P_{L,i}$ is the Langmuir pressure of component i (the pressure at which the adsorbed gas content is equal to $V_{L,i}$ / 2).

Geomechanics Effect on Natural Fractures. The economic production of shale gas reservoirs depends strongly on the stimulation of a dense and conductive fractures network in the drainage volume of the well, known as stimulated reservoir volume (SRV). The natural fracture network in the SRV is usually generated or rejuvenated because of the stress changes induced by hydraulic fracturing treatments (Y. Cho et al., 2013). However, it is very likely that the created fracture networks are unpropped or weakly propped. Therefore, the closing effect of the natural fracture networks during the production process needs to be considered in the simulation studies of shale gas reservoirs. We apply a practical approach in the developed simulator, for modeling the pressure-dependent permeability of natural fractures (R. Raghavan et al., 2004):

$$k_f = k_{fi} exp\{-d_f(p_{fi} - p_f)\} \tag{8}$$

Where k_{fi} is the permeability of fracture at initial conditions; d_f is the pressure-dependent coefficient, which can be determined experimentally. For an unpropped natural fracture in shale, d_f can be very large, which may play a significant role on shale gas production (E. Ozkan et al., 2010). Other correlations for the function of pressure-dependent permeability could also be easily implemented if available.

Gas Properties.

Density. Because hydrocarbon reservoirs have condition of high temperature and pressure, it is inaccurate to treat physical behavior of natural gas as ideal gas. We use Peng-Robinson equation of state to calculate gas density in the developed simulator. The EOS can be transformed into a cubic equation expressed by the compressibility factor:

$$Z^3 + sZ^2 + qZ + r = 0 \tag{9}$$

Where, $\begin{cases} s = B - 1 \\ q = A - 3B^2 - 2B \\ r = -AB + B^2 + B^3 \end{cases}$, $\begin{cases} A = ap/(R^2T^2) \\ B = bp/(RT) \end{cases}$, $a = \sum_{j=1}^{n_c}\sum_{i=1}^{n_c} x_i x_j (1 - k_{i,j})\sqrt{a_i a_j}$, $b = \sum_{i=1}^{n_c} x_i b_i$

$$b_i = \frac{0.078RT_{Ci}}{P_{Ci}} , \quad a_i = \frac{0.457R^2T_{Ci}^2}{P_{ci}}\left\{1 + f_w\left[1 - \left(\frac{T}{T_{Ci}}\right)^{0.5}\right]\right\}^2 , \quad f_w = 0.375 + 1.542\omega_i - 0.270\omega_i^2$$

And T_{Ci} and P_{Ci} are the critical temperature and critical pressure of each component; ω_i is the acentric factor of each component; $k_{i,j}$ is the binary interaction parameter. For gas phase the largest real root of cubic EOS can be used, and the molar density of gas is:

$$\rho_g = \frac{p}{RTZ} \tag{10}$$

Viscosity. The Dempsey method (1965) is applied for calculating viscosity of natural gas:

$$\mu = \mu_{g1} exp\left\{ln\left(\frac{\mu_g}{\mu_{g1}}T_{pr}\right)\right\} / T_{pr} \tag{11}$$

Where, $\mu_{g1} = (1.7 \times 10^{-5} - 2.1 \times 10^{-6}\gamma_g)(1.8T + 32) + 8.2 \times 10^{-3} - 6.2 \times 10^{-3} \log \gamma_g$

And $ln\left(\frac{\mu_g}{\mu_{g1}}T_{pr}\right)$ in Eqn.(9) can be expressed as a function of pressure, temperature and a series of correction coefficients; T_{pr} is the pseudo reduced temperature of the gas mixture, and γ_g is the relative density.

Numerical Model and Simulation Approach

We develop a novel multi-continuum multi-component model which incorporates several flow and transport mechanisms to investigate CO_2-EGR process with carbon sequestration in shale gas reservoirs. Multiple domains of complex fracture networks are successfully simulated through the integration of EDFM, dual-porosity concept and MINC method. The control-volume finite-difference formulation (CVFD) which is very flexible for handling interactions between various kinds of continua is applied for discretizing fluid equations. Time discretization is carried out using a backward, first-order, fully implicit FD scheme. The corresponding Jacobian matrix is evaluated by Automatic Differentiation with Expression Templates Library (ADETL), which provides a numerical framework allowing wide flexibility in the choice of variable sets and generic representations of discretized expressions for gridblocks.

Control-Volume Finite-Difference Formulation. The Control-Volume approach provides a general spatial discretization shceme that can represent a three-dimensional domain using a set of discrete meshes. The flow and transport properties in each mesh are represented by proper averaging over certain control volume, while fluxes of mass across surface segments are evaluated through finite difference approximations (K. Pruess et al., 1985). Considering single-phase multi-component flow model for shale gas reservoirs, the general discrete nonlinear equations for gridblock i of component c can be written as:

$$\frac{V_i}{\Delta t}\left\{(\phi\rho_g x_c)^{n+1} + m_c^{n+1} - (\phi\rho_g x_c)^n - m_c^n\right\} = \sum_{s=1}^{ns} Flux_{ij}^{n+1} - Q_{i,c}^{n+1} \tag{12}$$

The well term for gridblock i of component c can be written as follows. If is injector, ρ_g and x_c denote gas molar density and molar fraction of component c in the wellbore.

$$Q_{i,c} = WI\{\lambda\rho_g x_c(p_i - p^W)\} \tag{13}$$

The molar rate of component c exchanged through computational volume i and j:

$$Flux_{ij} = T_{ij}\left(\lambda\rho_g x_c \Delta\Phi\right)_{ij}^{n+1} \tag{14}$$

Where V_i is the bulk volume; T_{ij} is the transmissibility of the connection; λ is the flow mobility, which is k/μ; ns is the number of connections for gridblock i; WI is the well index; The flow potential between gridblock i, j is:

$$\Delta\Phi_{ij} = \Delta p - \gamma_{ij} g \Delta D \tag{15}$$

Fig.1 shows the schemetic of connection between control volumes by an example of PEBI meshes. The transmissibility between gridblock i, j can be computed as:

$$T_{ij} = \frac{A_{ij}}{d_i + d_j} \tag{16}$$

An important aspect of C-V formulation is that the geometry informations required for evaluating the connection between two volume elements in computational domain are provided directly as input data rather than having them generated from data on mesh arrangements. Therefore, this approach is very flexible for allowing any kinds of communications between continua, particularly useful in the modeling of fractured porous media (K. Pruess et al., 1985).

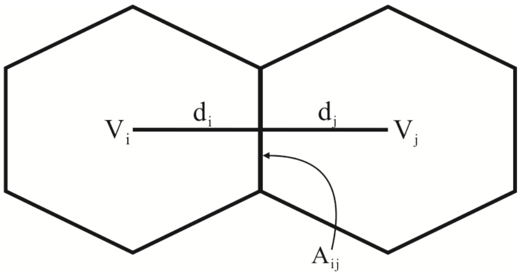

Fig.1 Connection between control volumes

Hybrid Method for Handling Fracture Networks. Shale gas reservoirs are naturally fractured but in order to achieve economic productivity, wells should intersect an extensive network of fractures through hydraulic fracturing treatments. The stimulated reservoir regions normally include fractures of multiple-length scales, which are very challenging for simulating.

Dual-Continuum models are widely used in the industry for simulations of naturally fractured reservoirs. The method could be more appropriate for describing a large amount of small-scale natural fractures which connect the global flow in the reservoirs for the reasons that: 1) it is not practical to treat small-scale fractures explicitly due to the highly computational efficiency; 2) detailed characterization of pre-existing natural fractures is often unavailable, or the high resolution of seismic data for mapping natural fractures could not be achieved due to economic considerations; 3) the densely-distributed fractures network modeling by DFM is not well suitable for history matching techniques, which often applied in field practice during reservoir characterization process.

Because of the ultra-low matrix permeability in shale formations, it is inaccurate to treat fracture-matrix flow as pseudo-steady state. Therefore MINC method was established to modify traditional dual-continuum models for treating the transient interaction between matrix and fractures in a realistic way (K. Pruess, 1985; Y. Wu and K. Pruess, 1988). The key aspect of MINC model is the generation of computational meshes by sub-dividing each matrix cell into a series of nested sub-cells. On the basis of the assumption that global flow occurs through the network of well-connected fractures, the reservoir could be partitioned into "primary" gridblocks which contain groups of elementary units for nested-matrix and fracture continuum. The 3-D configuration of the dual-continuum model comprises three orthogonal sets of natural fractures. The schematic of the MINC model is shown in Fig.2.

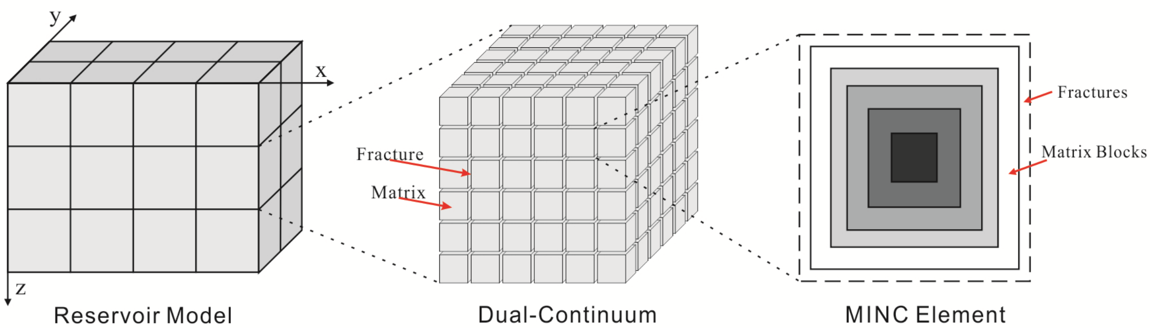

Fig.2 MINC concept of dual-continuum model

We apply a coupled MINC model in the developed simulator for incorporating storage and transport mechanisms of shale matrix. Advection and diffusion are considered in the gas flow, and instant sorption model represented as source-sink term is used for desorption process. In addition, sub-grids are logarithmic away from the fracture's surface to provide good resolution. Fig.3 shows the schematic for the coupled process of gas flow. The proposed approach can be easily extended to describe more complex multi-continuum model which couples kerogen, matrix and fractures if the distribution of organic matter is available. We also develop the preprocessing code for computing geometric parameters of the MINC model from the specification of fracture spacing L, aperture δ, and volume fractions f_i occupied by the interacting continuums. We assume that $i = 1$ refers to the outer fracture continuum, then can obtain volume fraction of fracture from L and δ:

$$f_1 = [L^3 - (L - \delta)^3] \,/\, L^3 \approx 3\delta \,/\, L \tag{17}$$

The other volume fractions can be chosen for providing good resolution where needed, except for the constraint that the summation of them equals to one. Then the parameters A_{ij}, d_{ij} and V_i needed for computing the accumulation terms and transmissibility of connections can be derived subsequently (K. Pruess et al., 1985). It should be noted that the fracture permeability need conversion to effective permeability when computing the connections between fractures or with other continuums. The coefficient should be multiplied is:

$$\beta = [L^2 - (L - \delta)^2] \,/\, L^2 \approx 2\delta \,/\, L \tag{18}$$

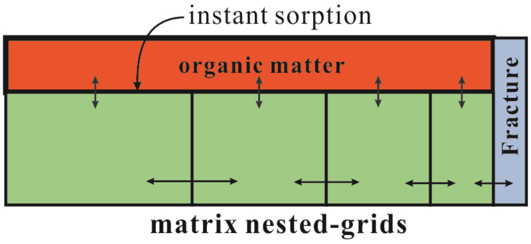

Fig.3 Coupled gas flow in MINC model (modified from Dahaghi, 2010)

Conventional dual-continuum models may induce inaccuracy in the presence of highly localized and anisotropic fractures which dominate the flow channel. Therefore hydraulic fractures and large-scale stimulated natural fractures in shale gas reservoirs are better handled by the discrete fracture model (DFM). S.H. Lee et al. (2001), Liyong Li et al. (2008), H. Hajibeygi et al. (2011) and Ali Moinfar et al. (2012) developed and improved a novel method called embedded discrete fracture model (EDFM), which is very flexible and computational efficient for simulating complex fractures network. EDFM apply the concept of wellbore index (WI) to derive the transfer index between fracture and matrix gridblock. Fig.4 shows an EDFM example of fractures network intersected by horizontal wellbore. From the figure we can see that EDFM allows various kinds of connections such as frac-frac, frac-matrix and frac-well.

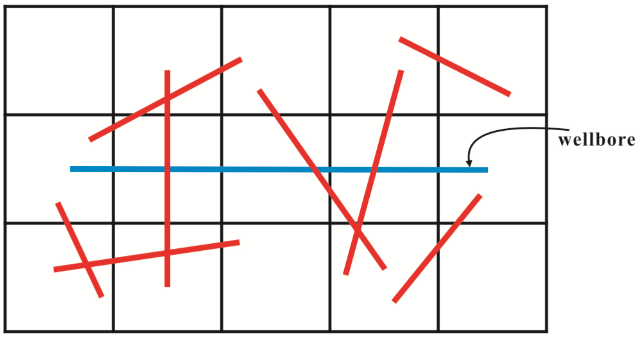

Fig.4 EDFM with fractures network intersected by horizontal wellbore

We propose a hybrid model to provide more flexibility for the communication between explicit "primary" fracture and natural fracutre network because the dual-continuum concept we applied in the reservoir. Note that the well-developed small-scale natural fractures network activated by stimulation job connects the global flow in the reservoir. Therefore we assume "primary" fractures first interact with the fracture media of dual-continuum, and the mass transfer contributed by matrix continuum could be neglected under the framework of our hybrid model. Fig.5 illustrates the connection list of continua in computational domain for a simple scenario. The embedded fractures are discretized vertically and horizontally by the cell boundaries of gridblocks.

The key aspect of the hybrid model is the calculation of connection transmissibility for flux interaction between different continua. Lee et al. (2001, 2000) assume that the pressure around a fracture is linearly distributed, and with this approximation the average normal distance from the fracture in the gridblock can be computed as:

$$\langle d \rangle = \frac{\int \vec{n} \cdot x dS}{S} \tag{19}$$

Thus the transmissibility is:

$$T_{ij} = \frac{A_{ij}}{\langle d \rangle} \tag{20}$$

Where $\vec{n}$ is the unit normal vector; x is the distance from the fracture; dS and S are the areal element and area of the gridblock, respectively; A_{ij} is the fracture surface area in the gridblock. Because the "primary" fracture connects with the natural fracture of dual-continuum model, the permeability in the flux term is the equivalent permeability of natural fracture corrected by the coefficient β as discussed before. For the fractures not fully penetrating the gridblock, we assume that T_{ij} is linearly proportional to the fracture length inside the gridblock (Liyong Li et al., 2008).

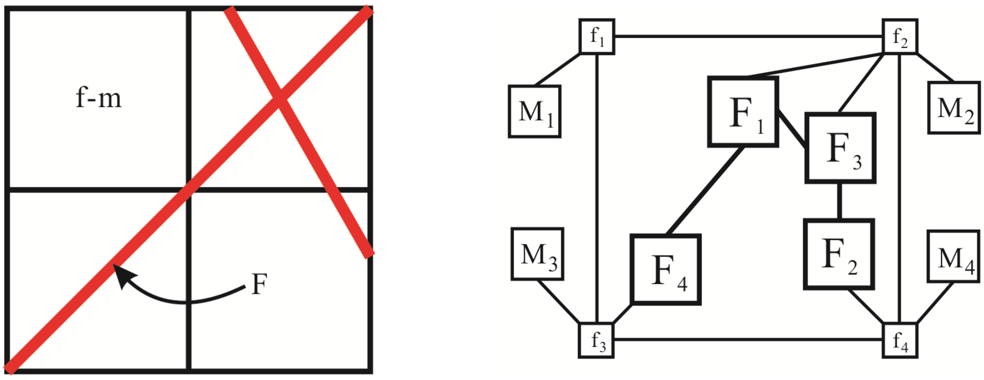

Fig.5 The example of connection list for EDFM coupled with MINC

Under the framework of the developed hybrid fracture model, we intend to obtain the balance among simulation accuracy, computational efficiency and field practice in the reservoir characterization process. Advanced characterization methodologies such as micro-seismic mapping are now able to provide realistic geometry of fractures network in stimulated shale gas formations. Fig.6 shows a typical M-S pattern for a horizontal well after water-frac stimulation treatment. Although the microseismic events display the spatial locations where the rock has been broken or fractured, small-scale hydraulically created fractures in SRV region are generally not present because of the resolution limitation for the method. Moreover, even if the detailed mapping of the fractures is available, it is not practical to use complex DFMs directly for simulating gas production process at field-scale. Upscaling procedures were introduced to improve the performance of dual-porosity approach by calculating equivalent properties of fractures network from more accurate DFMs (B. Dershowitz et al., 2000; Y. Ding et al., 2006). In order to maintain the advantages of the DP model without losing the dominant role of "primary" fractures as fluid conduit connecting reservoir with wellbore, an integrated workflow for the establishment of simulation model is proposed, as shown in Fig.7.

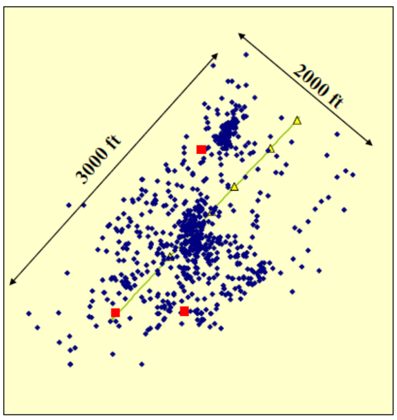

Fig.6 M-S pattern for a water-frac horizontal well (C.L. Cipolla, 2009)

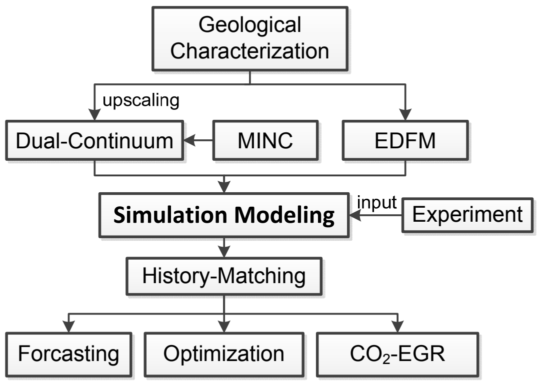

Fig.7 Integrated workflow of simulation studies

Note that DP model is more suitable for history-matching problems, and the geological information for "primary" (large-scale) fractures derived from characterization techniques generally have more certainty and reliability. Therefore the small-scale natural fractures in SRV regions of shale gas reservoir should be simulated using DP model through upscaling procedures, while the "primary" fractures generated by hydraulic fracturing are better described by EDFM for gaining accuracy of well productivity which could be greatly enhanced by the intersected fractures network. Then the well-testing and production data can be assimilated for calibrating the flow properties of fractures network in DP model through automatic history-matching process. Finally, we can perform production forecasting and optimization with the validated simulation model for maximizing economic benefits.

Automatic Differentiation Framework Based on ADETL. With growing needs for accurate modeling of subsurface flow in heterogeneous reservoirs and increasing computational power, more and more physical, chemical, and geo-mechanical phenomena must be incorporated in general-purpose reservoir simulators. As a consequence, the nonlinear governing equations grow in size and complexity. Fully-implicit methods, which are unconditionally stable, are generally applied to ensure stability. In order to obtain the solution to the coupled nonlinear system of equations under the fully-implicit scheme, Newton's method is widely used.

In addition to the linear solution of the linearized system, discretized residual equations and Jacobian matrix should be implemented and computed in each Newton iteration. As for Jacobian generation, manual differentiation is the most common approach in today's commercial and publicly available simulators. However, the computation of hand (manual) derivateves is both tedious and error prone.

ADETL stands for Automatically Differentiable Expression Templates Library, which was conceived and developed by R. Younis et al. (2007). The numerical framework based on ADETL allows wide flexibility in the choice of variable sets and provides generic representations of discretized expressions for gridblocks. It could provide data-structures and algorithms that exploit the power of the operator overloading approach, while overcoming the inefficiency usually associated with it (D. Voskov et al., 2009). Under the ADETL framework, the Jacobian derived from linearization process can be easily computed without any hand differentiation. As a result, the user can save a lot of time in the development and debugging stages of a reservoir simulator. Moreover, due to the computational efficiency of ADETL, the user is able to get the new extensions and capabilities at a relatively small additional cost in simulation time.

In this paper, we develop a multi-continuum multi-component shale gas simulator based on ADETL framework. Further work may involve the extension to multi-phase compositional model which can simulate the gas-water flow induced by hydraulic fracturing, and the gas condensate behavior during production process of shale gas reservoirs.

Comprehensive Sensitivity Studies

Sensitivity analysis is a quantitative method for determining the effect of parameter variation on model results. Sensitivity studies are performed to identify the most influential reservoir and fractures parameters and provide critical guidance for stimulation design and production optimization. In this work, we carry out several simulation studies based on two scenarios to determine the key factors and physical mechanisms that affect the production performance during the development of shale gas reservoirs.

Single-Well Model. A base model is constructed to perform simulation studies for a single horizontal well with multiple hydraulic fractures in shale gas reservoir. Several reservoir and fractures parameters are analyzed, including adsorption, matrix apparent permeability and conductivity, spacing, half-length, pressure-dependent coefficient of the fractures network. The reservoir comprises a horizontal well with four stages hydraulic fractures, and the stimulated reservoir volume (SRV) region is described by dual-continuum model. The matrix continuum is sub-divided into four nested-cells to account for the transient gas flow from matrix to natural fractures. In addition, we assumed that gas is flowing into the wellbore only through primary fractures, and the Pfs fully penetrate the formation in vertical direction. The schematic of the base model is shown in Fig.8. The parameters assumed for the model are summarized in Table.1. The thermodynamic and adsorption properties of the components used for the simulation studies are summarized in Table.2.

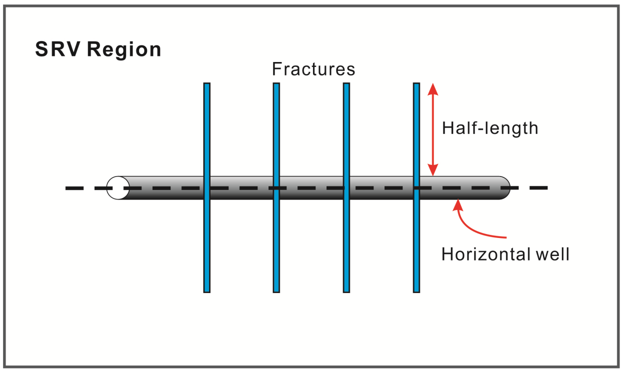

Fig.8 The schematic of the base model

Table.1 Parameters of the base model

Parameter	Value	Unit
Reservoir dimensions (x,y,z)	800, 500, 30	m
Gridblock size (x,y,z)	20, 20, 10	m
Initial reservoir pressure	12.0	MPa
Temperature	423	K
Matrix porosity	0.1	
Fracture porosity	0.5	
Nanopore radius	3.5e-9	m

Matrix nested-cells	4	
Fracture width	0.01	m
Rock density	2500	kg/m^3
Matrix Compressibility	1.0e-10	$1/Pa$
Fracture Compressibility	1.0e-8	$1/Pa$
Pressure-dependent coefficient	1.45e-7	$1/Pa$
Natural fracture permeability	5.0e-16	m^2
Natural fracture spacing	5.0	m
Hydraulic fracture permeability	1.0e-13	m^2
Hydraulic fracture number	4	
Hydraulic fracture half-length	100.0	m
Horizontal wellbore length	500	m
Well radius	0.1	m
Producer BHP	5.0	MPa

Table.2 Thermodynamic and adsorption properties of the components

	$P_c\ (MPa)$	$T_c\ (K)$	ω	P_L	$V_L\ (m^3/kg)$	$\rho_{gs}\ (kg/m^3)$
CH_4	4.6	190.6	0.011	6.7	0.021	0.71
N_2	3.4	126.1	0.037	28.4	0.0092	1.25
CO_2	7.4	304.1	0.224	3.4	0.062	1.96

Matrix factors. We study the effect of adsorption/desorption and apparent permeability on the well production rate. We compare the results of other 3 cases with the base model: without apparent permeability, without adsorption and setting matrix permeability as constant value of 0.5e-20m^2. Fig.9 shows the pressure profile of the natural fractures continuum in the base model at 2100 days. The ultimate drainage area is very limited due to the lack of complex and effective hydraulic fractures network intersected with the horizontal wellbore. Fig.10 shows the simulated production rate of the 4 cases during the 2100 days production period. We can see that apparent permeability only has impact on the early production period, probably because the spacing of the natural fractures is small ($5m$), which result in more elementary units for one "primary" gridblock. Thus the contact area between fractures and matrix continnum is large, and the effect of matrix permeability is reduced. Note that the matrix apparent permeability can be higher at smaller pore-scale and lower pressure. If matrix permeability becomes very low (0.5e-20m^2), considerable reduction of the production rate will still occur.

In addition, Fig.10 illustrates that gas desorption could have significant effect on well performance. As the reservoir pressure decreases, more adsorped gas is released from organic rock and produced. However, for some moderate to deep shale-gas reservoirs which have high initial pressure, the ability to produce the adsorbed gas is very limited because of the Langmuir soprtion profile, which requires relatively low pressure to expedite the desorption process. The impact of gas desorption can also be reduced as the natural fractures spacing increases and matrix permeability decreases.

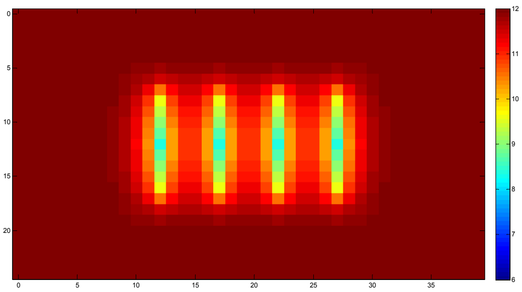

Fig.9 Pressure profile of the Nfs continnum in base model at 2100 days

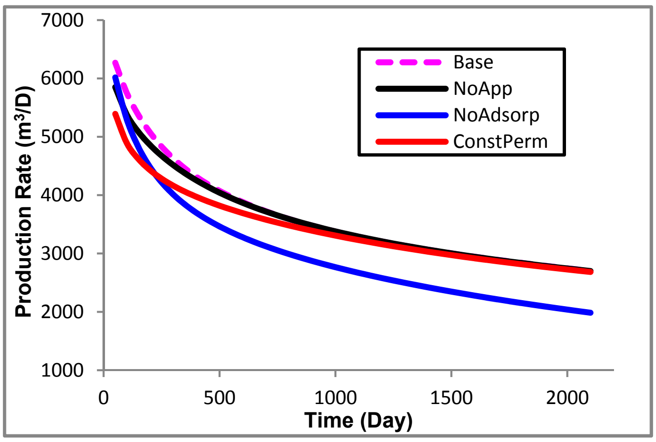

Fig.10 Effect of matrix factors on production rate

Natural fractures factors. A sensitivity study is performed on natural fracture permeability for 0.05, 0.5, $5md$, on spacing for 2, 5, $10m$, and on pressure-dependent coefficient for 1.45e-7, 8.0e-7, 1.45e-6. The impact of the three sets of parameters on the cumulative gas production is illustrated in Fig.11. The figure shows that these three properties of the natural fractures network are all influential factors for the gas recovery. Higher permeability and smaller spacing of the fractures network can result in more effective gas drainage from matrix and gas desorption from organic rock. We can see from the modeling results that production performance strongly depend on the existence of a dense and conductive network of fractures in the SRV region.

However, the natural fractures network created by water-frac treatments is usually un-propped or partially propped due to the use of low-viscosity fluid (water) and the placement of low-concentration proppant in the stimulation process for shale gas reservoirs. Therefore, the conductivity of the ineffectively propped natural fractures may play a significant role on well performance. Fig.11(c) illustrates the large impact of fractures' pressure-dependent coefficient on gas recovery. As the reservoir pressure decreases, significant permeability reduction of un-propped natural fractures network could occur. Therefore, it is important to create more effectively-propped stimulated fractures network after hydraulic fracturing treatment for maintaining the economic productivity of the wells in shale gas reservoirs. Another feasible measure for reducing the pressure-dependent effect of natural fractures is the injection of CO_2 into the reservoir during the later production life of the wells. The injected CO_2 could maintain the pore pressure, as well as expedite gas desorption process for improving the ultimate gas recovery.

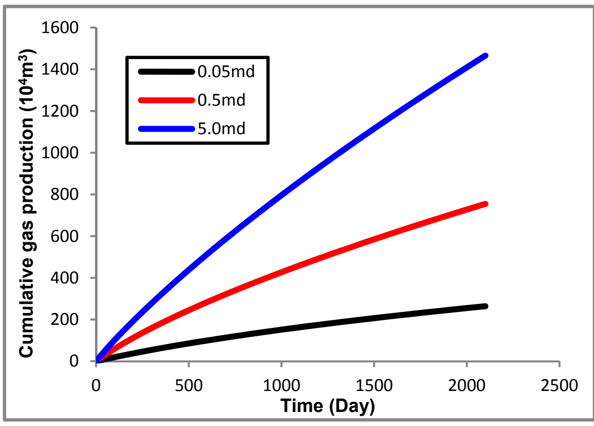

Fig.11(a) Natural fracture permeability

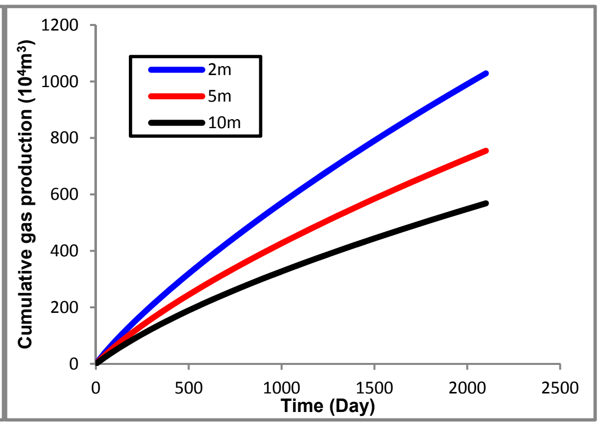

Fig.11(b) Natural fracture spacing

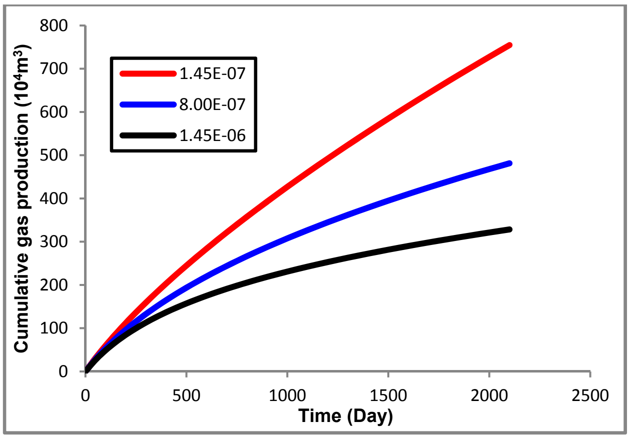

Fig.11(c) Pressure-dependent coefficient

Hydraulic fractures factors. Simulation study is performed on hydraulic fracture permeability for 10, 100, $1000md$, on number of stages for 4, 5, 6, and on half-length for 60, 100, $160m$. It is assumed that planar, primary fractures with width of $0.01m$ are hydraulically created from the perforation clusters in each stage of the wellbore. Fig.12 illustrates that hydraulic fractures' properties have significant impact on cumulative gas production. To improve the well productivity, effective primary fractures as high permeability conduits should be created and intersected with extensive network of natural fractures.

From Fig.12(a) we can see that high conductivity could lead to large enhancement for gas recovery. It should also be noted that in the absence of the primary fractures with relative high conductivity, drainage is much less effective and the cumulative production is very low. Increasing the fracture number and half-length leads to more contact between primary fractures and the reservoir, which results in better well performance. However, the fractures spacing should not be too small, because production improving trend will reach a critical value when fractures interfere strongly with each others. Fig.13 shows the pressure profile of the natural fractures continuum when primary fractures number is 6 after 2100 days.

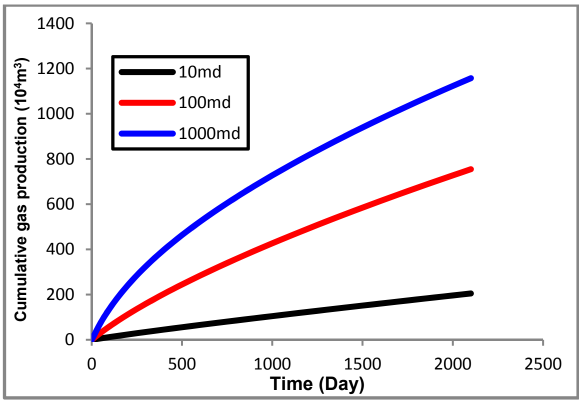

Fig.12(a) Hydraulic fracture permeability

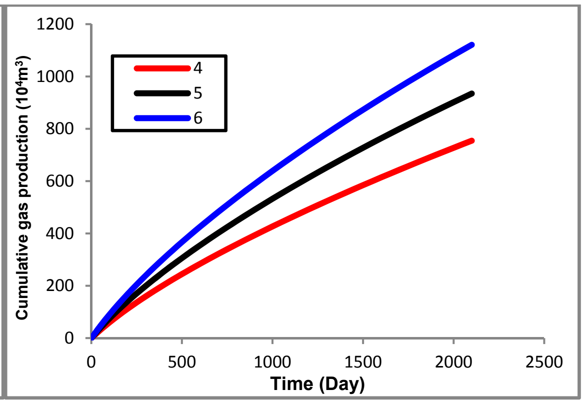

Fig.12(b) Hydraulic fracture number

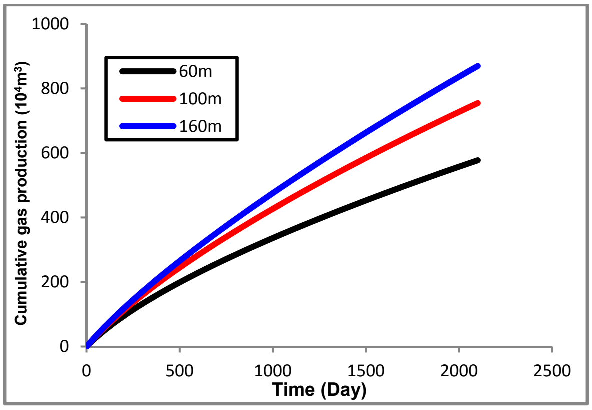

Fig.12(c) Hydraulic fracture half-length

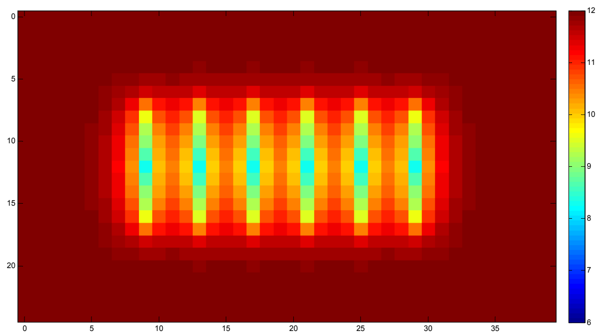

Fig.13 Pressure profile of 6 Pfs at 2100 days

Huff-n-Puff scenario. In order to investigate the effect of Huff-n-Puff scenario on CO_2-EGR process, we establish a simulation model with the geometry of complex primary fractures. Several parameters are modified from the base model we set up previously (the others remain unchanged), as summarized in Table.3. We first compare the cumulative production of the model with complex network of primary fractures to the case that has regular hydraulic fractures pattern (5 stages). The schematic for the model, simulation results and pressure profile of the natural fractures continuum after 1200/2100 days are shown in Fig.14/15/16, respectively. From the figures we can see that the hydraulic fractures network with much complexity could produce a more effective drainage pattern in the reservoir, therefore greatly improve the production performance.

Table.3 The modified parameters for Huff-n-Puff model

Parameter	Value	Unit
Reservoir dimensions (x,y,z)	600, 450, 30	m
Gridblock size (x,y,z)	30, 30, 10	m
Natural fracture permeability	1.0e-15	m^2
Natural fracture spacing	10.0	m
Hydraulic fracture permeability	5.0e-13	m^2
Hydraulic fracture number	5	
Hydraulic fracture half-length	120.0	m
Horizontal wellbore length	420	m
Production BHP	4.0	MPa
Injection BHP	15.0	MPa

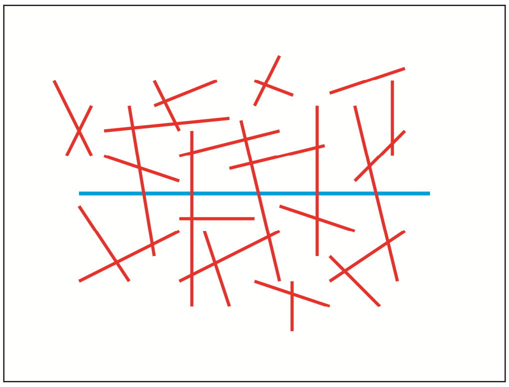

Fig.14 Primary fractures' pattern of the model

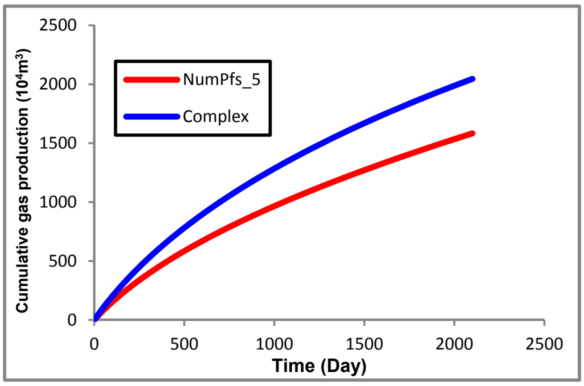

Fig.15 Cumulative gas production of the two cases

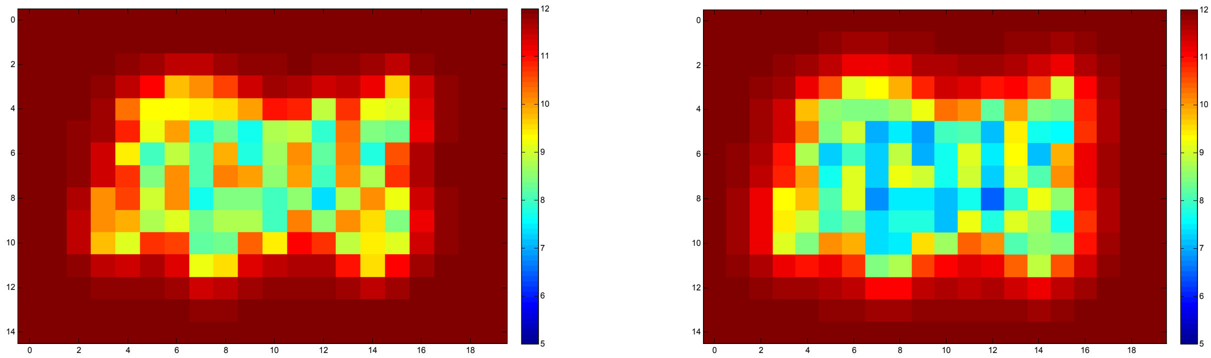

Fig.16 Pressure profile of the model with complex Pfs pattern at 1200/2100 days

Then we compare three cases to determine the better injection strategy for Huff-n-Puff scenario. The Huff-n-Puff patterns, and the ultimate cumulative production/injection of the modeling studies are summarized in Table.4. We fix the total production and injection periods (P_2800, I_1400) with different combinations. Fig.17 shows the impact of different strategies on cumulative methane production and CO_2 production/injection (minus values indicate the injection amount). From the results we can see that there is almost no enhancement for methane recovery in Huff-n-Puff scenario as compared to the base case. This is mainly due to the large amount of CO_2 desorped and reproduced after the injection periods. However, considerable net quantities of CO_2 are injected and sequestrated in the reservoir. Therefore we can conclude that Huff-n-Puff scenario may not be applicable to CO_2-EGR purpose for shale gas reservoirs, but can be considered as viable option for CO_2 capture and sequestration.

Table.4 Simulation patterns and results of Huff-n-Puff scenario

	Prod/Inj pattern (day)	Methane recovery (10^4m^3)	CO_2 production (10^4m^3)	Net CO_2 injection (10^4m^3)
Case_0	P_2800	2407.3		
Case_1	P_1400+I_1400+P_1400	2410.5	1121.5	2354.3
Case_2	P_1050+I_700+P_1050 +I_700+P_700	2304.1	1295.4	2483.1

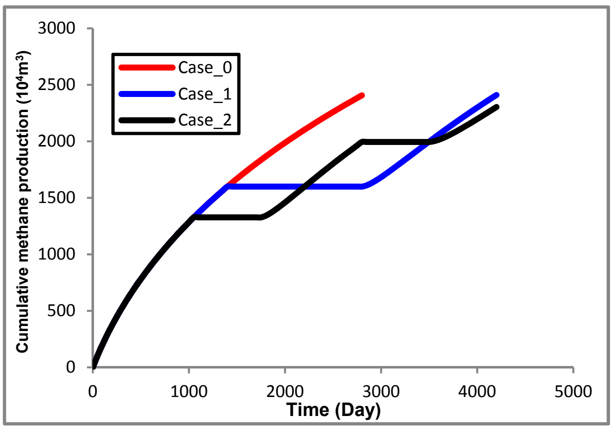

Fig.17(a) Cumulative methane production

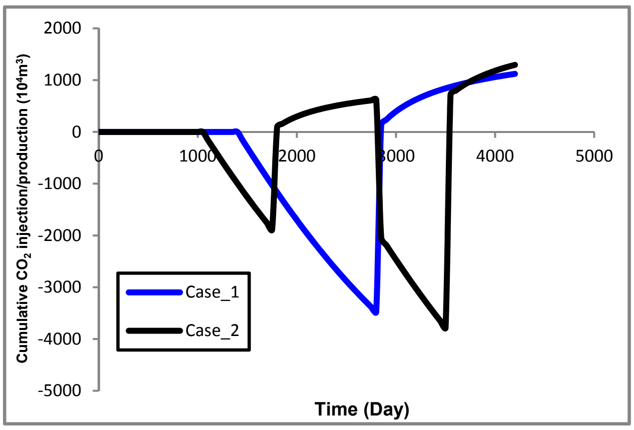

Fig.17(b) Cumulative CO_2 injection/production

Gas Injection Model for EGR. Laboratory and theoretical studies demonstrate that CO_2 is preferentially adsorbed over CH_4 with a ratio of up to 5:1 by molecule (Nuttall, 2010). Therefore, the competitive adsorption mechanism is expected to play a major role during CO_2-EGR process in shale gas reservoirs. In this work, a reservoir model with two parallel horizontal wells intersected by complex network of primary fractures is established, and simulation studies are performed to investigate the feasibility of EGR through CO_2/N_2 injection. The schematic of the model and the parameters modified from Table.1 (the others remain unchanged) are shown in Fig.18 and Table.5.

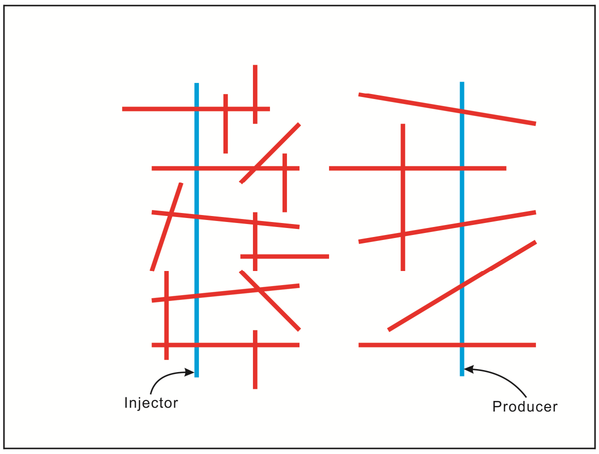

Fig.18 The schematic of gas injection model

Table.5 The modified parameters for gas injection model

Parameter	Value	Unit
Reservoir dimensions (x,y,z)	600, 450, 30	m
Gridblock size (x,y,z)	30, 30, 10	m
Natural fracture permeability	3.0e-15	m^2
Natural fracture spacing	5.0	m
Hydraulic fracture permeability	1.0e-12	m^2
Pressure-dependent coefficient	3.0e-7	
Production BHP	4.0	MPa
Injection BHP	16.0	MPa

We first perform a preliminary simulation without injector, then two cases with regular hydraulic fractures pattern (5 stages, $100m$ half-length) and complex network of primary fractures for the injector are ran and compared to examine the effect of well injectivity on CO_2 sequestration and methane recovery. The total production period is 3500 days, and the model start injecting CO_2 after 700 days. The cumulative methane production and CO_2 injection of the three cases are shown in Fig.19 (Because the CO_2 production rate is very low and could be neglected, the production history isn't shown). The figures illustrate that the methane recovery improve to some extent through CO_2 injection, and as injection ability increases the increment becomes larger.

Enhancement of methane recovery during CO_2-EGR process could be generated by either reservoir repressurization or CH_4 preferential replacement by CO_2. For the scenario that the hydraulically created natural fractures network is ineffectively propped, injecting CO_2 could also reduce the effect of pressure-dependent conductivity by maintaining the reservoir pressure. Fig.20/21 shows the CO_2 mole fraction of the outer nested-cell of matrix continuum and the pressure distribution of fracture continnum in the "complex" model after 2100/3500 days. At the end of production period, major CO_2 breakthrough isn't observed, which leads to very low CO_2 production rate in the producer. Although the increment of gas production through CO_2 injection is limited, the results show that this method still could be a feasible option with application potential for EGR in shale gas reservoirs. Significant recovery enhancement could be expected if we could create a more effective CO_2 displacement system by optimizing wells location and prod/inj pressure. In addition, large quantities of CO_2 sequestrated indicate that shale gas reservoirs could be good candidate for reducing carbon emission in the future.

We also run the other two cases for determining the effect of injected gas compositions on methane recovery. Fig.22 shows the cumulative methane production and cumulative CO_2/N_2 injection of the cases under different compositions of the injected gas mixtures. The result show nearly negligible variations of methane recovery for different gas compositions, which indicate that nitrogen also could be injected for EGR purpose in shale gas reservoirs. Note that the injected nitrogen play a role for lowering the partial pressure of methane, hence accelerate the desorption process of methane from organic matter.

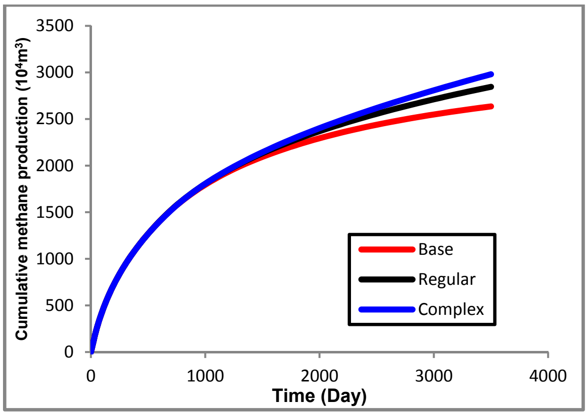

Fig.19(a) Cumulative methane production of the three cases

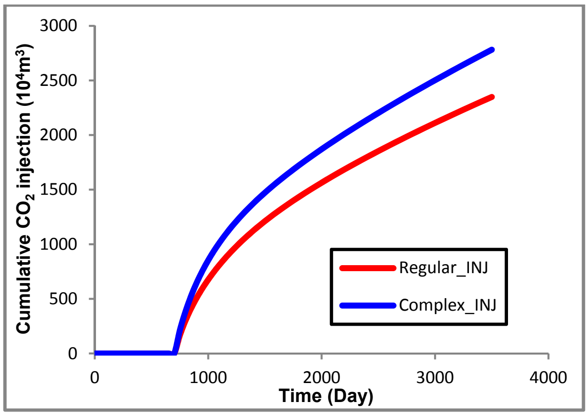

Fig.19(b) Cumulative CO_2 injection of the two cases

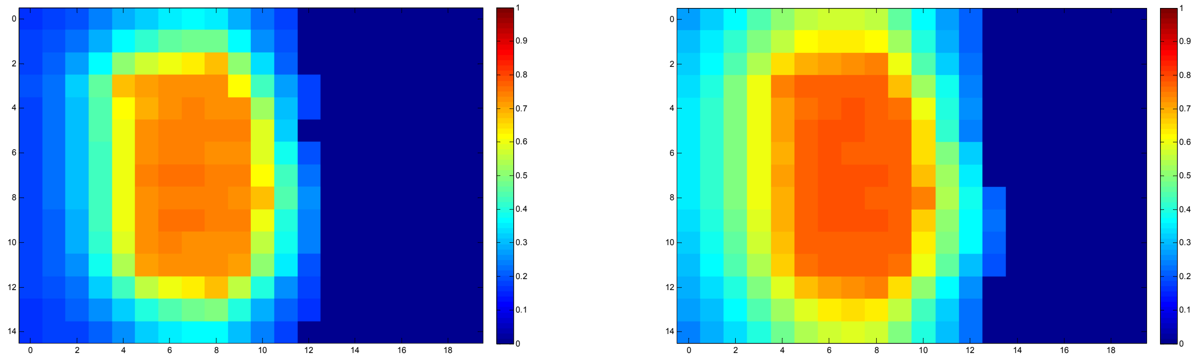

Fig.20 CO_2 mole fraction of the outer nested-cell of matrix continuum in "complex" model after 2100/3500 days

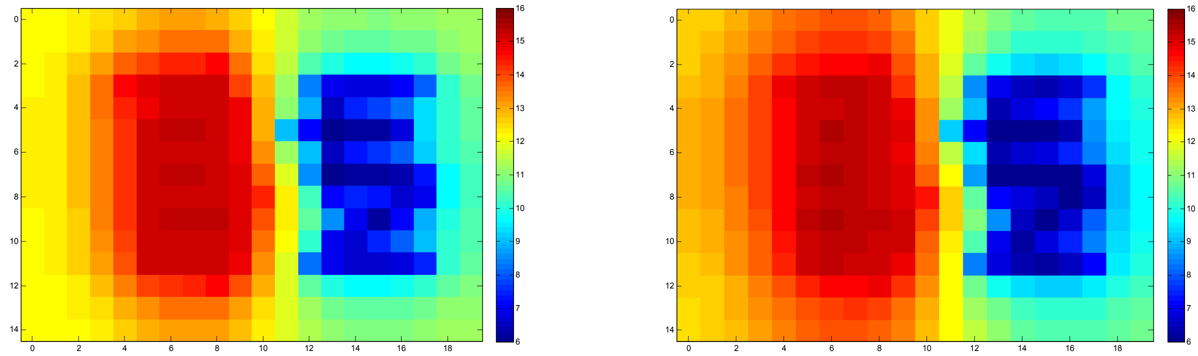

Fig.21 Pressure distribution of fracture continuum in "complex" model after 2100/3500 days

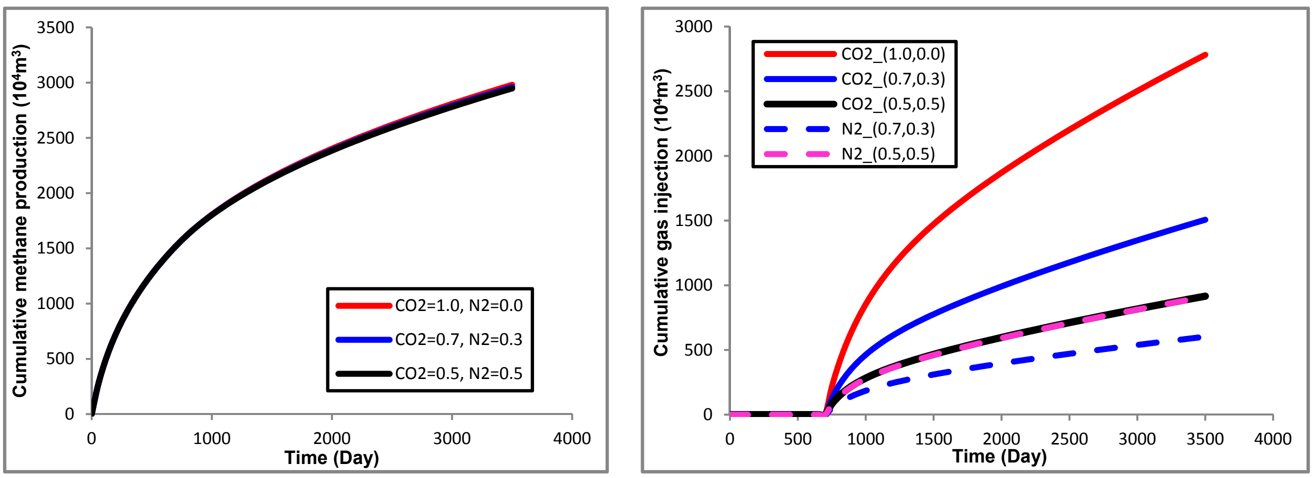

Fig.22 Cumulative methane production and cumulative CO_2/N_2 injection under different gas compositions

Conclusions

In this work, we develop a multi-continuum simulator that simultaneously incorporates the effects of Knudsen diffusion, gas-slippage and multi-component sorption behavior for CO_2-EGR process in fractured shale gas reservoirs. We implement a novel method in the simulator that integrates Embedded Discrete Fractures Model (EDFM), dual-continuum, and Multiple Interacting Continua concept (MINC) for successfully simulating the complex fractures network with multiple orientations and length-scales induced by hydraulic fracturing treatment. The hybrid model could explicitly describe the dominant role of "Primary" (large-scale) fractures on flow conduits, as well as offer computational-efficient simulations without employing unstructured gridding and mesh refinement near fractures. The natural fractures network connecting the global flow is simulated by dual-continuum model with MINC concept, which is more suitable to history-matching process and could capture the transient flow from ultra-tight matrix to fractures in shale gas reservoirs. The proposed numerical model is designed and applied using a generic abstraction that is built on top of the Automatically Differentiable Expression Templates Library (ADETL). Finally we conduct comprehensive modeling studies towards understanding the key reservoir and fracture properties that affect the production performance, and investigating the feasibility of CO_2/N_2 injection for carbon sequestration and enhanced methane recovery in shale gas reservoirs. We could obtain following conclusions from the simulation results:

1) The apparent permeability appears to have minor effect on gas production for the scenario simulated in this work. The effect of adsorption is significant, but may depend on the conductivity and spacing of the natural fractures network;
2) Fractures' properties (both natural and hydraulic) could have large impact on well productivity. The "Primary" fractures network with high complexity could result in more effective drainage area in shale gas reservoirs. The pressure-dependent effect on the permeability of ineffectively-propped natural fractures could greatly influence the production performance as reservoir pressure decreases;
3) Huff-n-Puff scenario may not be applicable to CO_2-EGR purpose for shale gas reservoirs, but could be a viable option for carbon capture and sequestration;
4) CO_2 injection into shale gas reservoirs appears to be a technically feasible method for CO_2 storage and methane recovery enhancement. In addition, injected gas mixture with different compositions of CO_2/N_2 seems have minor effect on methane recovery, indicating that nitrogen also could be chosen for EGR in shale gas reservoirs.

Acknowledgement

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Nomenclature

ϕ	Porosity
k	Permeability, m^2
k_D	Absolute Darcy permeability, m^2
k_m	Effective Darcy permeability, m^2
k_{app}	Apparent permeability, m^2
k_f	Permeability of natural fracture, m^2
d_f	Pressure-dependent coefficient
r	Pore radius, m
R	Gas constant, $8314\, J.kmol^{-1}.K^{-1}$
T	Absolute temperature, K
M_i	Molar weight, $kg.kmol^{-1}$
α	Tangential momentum accommodation coefficient
τ	Tortuosity of porous medium
μ	Viscosity, $Pa.s$
x_i	Component mole fraction
γ	Gas mass density, $kg.m^{-3}$
ρ_g	Gas molar density, $kmol.m^{-3}$
ρ_R	Rock bulk density, $kg.m^{-3}$
ρ_{gs}	Gas molar density at standard condition, $kmol.m^{-3}$
V_i	Adsorption term, $m^3.kg^{-1}$
$V_{L,i}$	Langmuir volume, $m^3.kg^{-1}$
$P_{L,i}$	Langmuir pressure, Pa
m_i	Adsorbed mole in unit formation volume, $kmol.m^{-3}$
υ	Darcy velocity, $m^2.s^{-1}$
q_i^w	Source/sink term, $kmol.m^{-3}.s^{-1}$

q_i^{conn} Flux term between continuums, $kmol.m^{-3}.s^{-1}$
n_c Number of components
p Pressure, Pa
p^W Well bottom-hole pressure, Pa
Z Gas compressibility factor
T_{Ci} Critical temperature, K
P_{Ci} Critical pressure, Pa
T_{pr} Pseudo reduced temperature
ω_i Acentric factor
$k_{i,j}$ Binary interaction parameter
γ_g Gas relative density
A_{ij} Surface area of connection, m^2
T_{ij} Transmissibility of connection, m
λ Flow mobility
ns Number of connections for the gridblock
WI Well index, m
L Natural fracture spacing, m
δ Natural fracture aperture, m
f_i Volume fraction
β Natural fracture effective permeability coefficient
$\langle d \rangle$ Average normal distance, m
$\vec{n}$ Unit normal vector

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