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A Multi-Porosity, Multi-Physics Model to Simulate Fluid Flow in Unconventional Reservoirs

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Abstract

Gas flow in shales is complicated by the highly heterogeneous and hierarchical rock structures (i.e., ranging from organic nanopores, inorganic nanopores, less permeable micro-fractures, more permeable macro-fractures, to hydraulic fractures). The dominant fluid flow mechanism varies in these different flow regimes, and properties of these rock structures are sensitive to stress changes with different levels. Although traditional single-porosity and double-porosity models can simulate certain time range of reservoir performance with acceptable accuracy, they are not generally applicable for the prediction of long-term performance and have limitations to improve our understandings of enhanced hydrocarbon recovery. In this paper, we present a multi-domain, multi-physics model, aiming to accurately simulate the fluid flow in shale gas reservoirs with more physics-based formulations.

An idealized model has been developed for the purpose of studying the characteristic behavior of a fractured nanopore medium, which contains five regions: organic nanopores, inorganic nanopores, local micro-fractures, global natural fractures, and hydraulic fractures. Fluid flow governing equations in this model vary according to the different dominant fluid flow mechanisms in different regions. For example, the apparent permeability, which is the intrinsic permeability multiplied by a correction factor, is used to account for the gas slippage through nanopores of shale matrix; while the organic and inorganic nanopores in this matrix have different capacities for gas adsorption. On the other hand, for fluids flow in natural fractures and hydraulic fractures with high velocity, the non-Darcy flow model is used to capture the strong inertia when is comparable to viscous force.

Numerical studies with practical interests are discussed. Several synthetic, but realistic test cases are simulated. Input parameters in these cases are evaluated using either the laboratory or theoretical work. Our results demonstrate that this model is able to capture the typical production behavior of unconventional reservoirs: a great initial peak, the sharp decline in the first few months, followed by a long flat production tail. A series of sensitivity analyses, which address the organic matter content, organic matter connectivity, natural fracture density, and hydraulic fracture spacing, will also be conducted.

Introduction

Shale gas refers to the natural gas trapped in shale formations. With continuous technical innovations in horizontal drilling combined with hydraulic fracturing, these previously unproductive organic shales are converted into some fields with huge commercial productivity, and they are believed to be an important part of the future energy mix within the US and around the world.

For these reservoirs, similar to conventional reservoirs, numerical modeling of fluid flow in subsurface is an effective tool for reservoir management and development as it can help on decision makings about optimizing the well completion method, identifying the present or future needs of artificial lift, and estimating the optimal number of wells required, etc. The traditional reservoir simulation, which is a relatively mature technology since 1960s, has been applied to shale gas reservoirs for these purposes. Although traditional single-porosity and double-porosity models can simulate certain time range of reservoir performance with acceptable accuracy, they are not generally applicable for the prediction of long-term performance.

Gas flow in shales is complicated by the highly heterogeneous and hierarchical rock structures (i.e., ranging from organic nanopores, inorganic nanopores, less permeable micro-fractures, more permeable macro-fractures, to hydraulic fractures). Shale gas reservoirs have the following three characteristics differentiating itself from conventional petroleum reservoirs: extremely small pores, the presence of both organic and inorganic porosity, and complicated fracture systems. In addition, these characteristics lead to the corresponding complexities and challenges for flow modeling and simulation described in this section.

Extremely small pores

Many techniques (e.g. SEM, FE-SEM, MICP, and NMR) have been used to analyze pores in rocks from different shale plays (Loucks et al., 2012; Loucks et al., 2009; Nelson, 2009). They show that a combination of nanopore networks connected to micrometer pore networks controls the gas flow in shale, and the dominate pores are in the scale of nanometer. This pore-throat size is almost the same as the size of asphaltene molecule, 50 times larger than the size of light oil molecular, and 100 times larger than the size of methane molecule. Conventional reservoirs are typically 3 or 4 orders of magnitude larger with respect to pore throat size than shales.

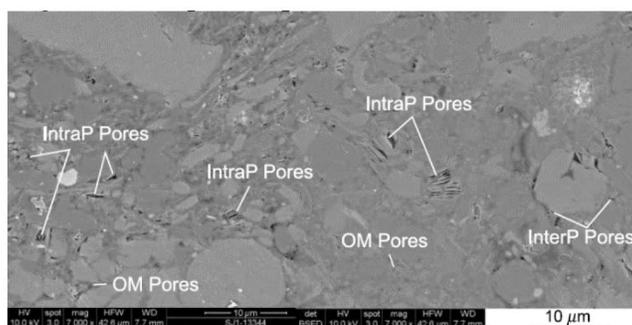


Figure 1—Intra- and inter-pores from the FE-SEM image (Loucks et al., 2012)

For gas flow in these extremely small pores, microscale analysis tells that with the increase of the ratio of molecule/wall to molecule/molecule collisions, the rarefaction effects become more prominent, and the continuum flow assumption breaks down into slip flow or even transition flow (Roy et al., 2003; Song et al., 2015; Soulaine, n.d.). For reservoir-scale simulation, however, fluid flow is preferred to be modeled using the continuum approach instead of the molecular approach, which means fluids are regarded not made up of discrete particles, but rather a continuous substance. After upscaling the microscopic behavior into macroscopic scale, the continuum flow can be described by Darcy's law with a constant value while if the slip flow regime is deployed, the coefficient of permeability is not a constant value but depends on the gas

pressure. Civan et al. (Civan et al. 2010) gave the apparent gas permeability which incorporates the suite of continuum, slip, transition, and Knudsen flow regimes in one equation:

$$k_a = k_{in} f(K_n) \quad (1.1)$$

where k_a is the apparent gas permeability, and k_{in} is the rock intrinsic permeability. The function of Knudsen number is given by,

$$f(K_n) = (1 + cK_n) \left(1 + \frac{4K_n}{1 - bK_n} \right) \quad (1.2)$$

where c is the dimensionless rarefaction coefficient and the slip coefficient b is an empirical parameter. Its value can be determined by the linearized Boltzmann equation.

The presence of both organic and inorganic porosity

The presence of organic porosity is another distinctive feature of shale gas reservoirs from conventional reservoirs. Shale gas reservoirs are self-sourced rocks containing a significant amount of organic matters, and the total organic carbon (TOC) are highly variable among different shales (Gu et al., 2016). Organic pores with a high degree of connectivity are reported to exist in most of these plays in addition to inorganic pores (Curtis et al., 2012; Wang and Reed, 2009). Depending on the content of TOC, these organic matters may be sparsely scattered in the inorganic matrix or may be joined to form an organic matter production fairway, and shale can show a dominance of one pore system or a combination of both. As a result, gas flow through these two porous media is predominantly either in series or in parallel.

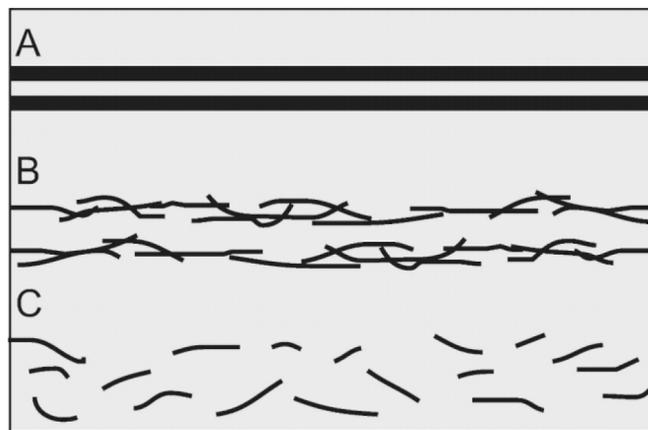


Figure 2—Hypothetical relationship between organic matter and inorganic matrix, organic matters may be sparsely scattered in the inorganic matrix or may be joined to form an organic matter production fairway (Loucks et al., 2009)

Fluid flow and storage mechanism in these organic pores are very different from that in inorganic pores. First, organic pores are typically one or two orders of magnitude smaller than those of inorganic pores (Wang et al., 2014; Yang et al., 2016), and thus the flow conductivity (permeability in reservoir simulation) for organic pores is smaller. Second, due to the difference in host materials, fluid-solid interactions for flow in this porous medium also vary considerably. Organic pores are strongly oil-wet, while inorganic pores are water-wet (Xu and Dehghanpour, 2014). The non-wetting phase will occupy centers of pores since it is the most energetically favorable. This micro-scale fluid distribution strongly affects the macro-scale multi-phase flow behavior, and locations of relative permeability curves are therefore different (Yassin et al., 2016).

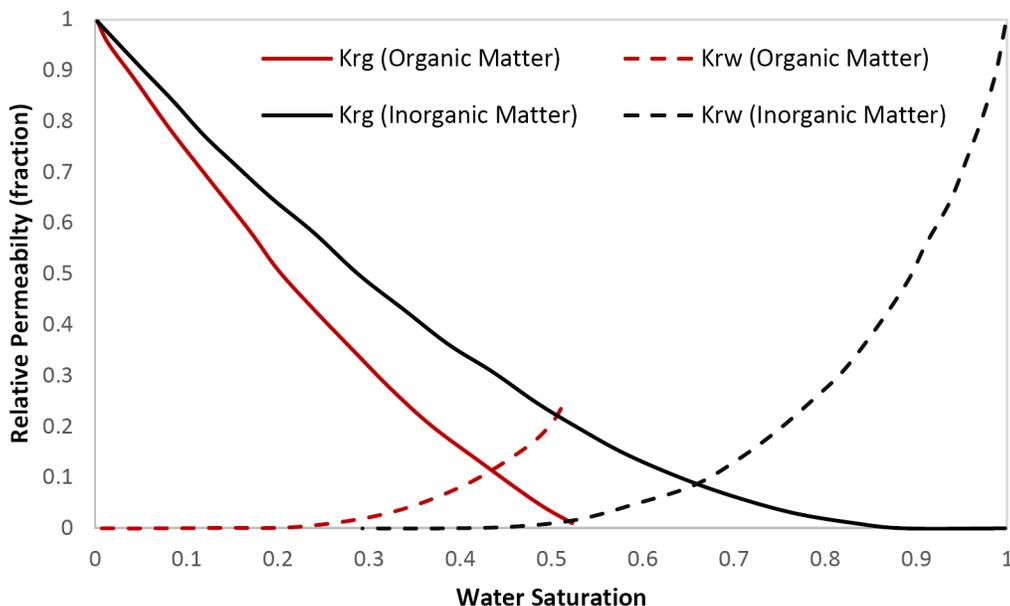


Figure 3—Water and gas relative permeability in organic and inorganic porous medium (Yassin et al., 2016)

In addition, most of the gas tends to adsorb on the surface of organic pores, as indicated by the experiment data that the total amount of adsorbed gas has a strong linear correlation with the organic matter content (Zhang et al., 2012). This adsorption phenomenon provides another mechanism of gas storage in addition to free gas and dissolved gas. The Langmuir's isotherm (Langmuir, 1918) is in general used to describe the gas content, V_E , typically measured as cubic feet of gas per ton of net shale (EIA, 2011; Mengal and Wattenbarger, 2011),

$$V_E = V_L \frac{P}{P + P_L} \quad (1.3)$$

where V_E is the gas content or Langmuir's volume in scf/ton (or standard volume adsorbed per unit rock mass); P is reservoir gas pressure; and P_L is Langmuir's pressure, the pressure at which 50% of the gas is desorbed. In general, Langmuir's volume, V_L , is a function of the organic richness (or TOC) and thermal maturity of the shale.

Complicated fracture system

Fractures seem ubiquitous in shale gas plays and their presence is one of the most critical factors in defining the economic prospect of shale play. Commercial hydrocarbon productions from these tight formations would be impossible without the extensive fracture networks. This is indicated from several numerical tests, which usually require permeability 2 to 4 orders of magnitude greater than the matrix permeability to match flow rates and ultimate recoveries (Stephen, 2009; Walton and McLennan, 2013). Fractures in unconventional reservoirs occur in a variety of scales, which scopes from micro-fractures, small- and intermediate-scale fractures, to hydraulic fractures (Gale, et al., 2007). These fractures with different scales significantly increase contact areas between fractures and matrix systems, which may potentially impact overall flow and transport processes. Natural fractures in unconventional systems can be either partially opened or fully sealed. In the latter case fractures cannot contribute to reservoir storage or enhanced permeability. These fractures, however, can act as planes of weakness and be reactive during hydraulic fracture treatments (Gale et al., 2007). The population of these induced fractures follows a power-law probability distribution. This is different from conventional fractured reservoirs in which natural fractures are much less influenced by human activities and thus are mostly uniformly distributed. Though natural

fractures contribute negligibly to the pore volume of the reservoirs (cumulative fracture porosity ranges from 0.0003 – 0.0005%), they are significant to the flow capacity.

Although traditional single-porosity and double-porosity models can simulate certain time range of reservoir performance with acceptable accuracy, they are not generally applicable for the prediction of long-term performance and has limitations to improve our understandings of enhanced hydrocarbon recovery (Cai et al., 2015). As discussed above, gas flow in shales is complicated by the highly heterogeneous and hierarchical rock structures (i.e., ranging from organic nanopores, inorganic nanopores, less permeable micro-fractures, more permeable macro-fractures, to hydraulic fractures), which are not considered in traditional modeling efforts. To overcome these gaps, we should build a model not from the single set of porosity and permeability (though petroleum geologists and engineers are accustomed to these two parameters), but from fundamental features discussed above. In this paper, an idealized model has been developed for the purpose of studying the characteristic behavior of a fractured nanopore medium which contains five regions: organic nanopores, inorganic nanopores, local micro-fractures, global natural fractures, and hydraulic fractures. Fluid flow governing equations in this model vary according to the different dominant fluid flow mechanism in different regions. Key parameters in the calculation setup are determined and given. For example, the apparent permeability, which is the intrinsic permeability multiplied by a correction factor, is used to account for the gas slippage through nanopores of shale matrix; while the organic and inorganic nanopores in this matrix have different capacities for gas adsorption.

Mathematical Formulation and Numerical Framework

We adopted a numerical framework into which the multi-porosity, multi-physics model can be easily implemented (Pruess et al., 1999; Pruess, 2004; Wu and Pruess, 1998; Xiong et al., 2015). Versatility and scalability are two important features of this framework. This framework has been successfully applied for large-scale numerical simulation of nuclear waste disposal, environmental remediation problems, energy production from geothermal, oil and gas reservoirs, geological carbon sequestration, and etc. In this section we will briefly discuss several key features for this function. The integral finite difference method is used to discretize the space variables, which starts from the integral form of mass conservation equations rather than the partial differential form.

$$\frac{d}{dt} \int_{V_n} M_\alpha^\kappa dV_n = \int_{\Gamma_n} F_\alpha^\kappa \cdot n d\Gamma_n + \int_{V_n} q_\alpha^\kappa dV_n \quad (1.4)$$

where V_n is an arbitrary subdomain for integration bounded by the close surface Γ_n . The quantity M , F , and q denote the accumulation term (mass per volume), mass flux term, and sink/source term respectively. n is a normal vector on surface pointing inward into the element. κ and α label the fluid component and flow continuum.

Equation (1.4) is discretized using the intergral finite difference approach and this discretization method avoids references to the global coordinates, requiring only local connection information. So it can easily deal with regular and irregular grids. And through this approach the double- or multi-porosity models can be easily implemented into reservoir simulation in the pre-processing section. All the variables involved in the calculation are divided into two groups, primary variables and secondary variables. The number of primary variables per grid is equal to the number of mass conservation equations. The simulator essentially solves these mass conservation equations for primary variables as a function of time with the knowledge of initial conditions. At each time step, once the primary variables are obtained, secondary variables can then be updated through the constitutive law. In solving these nonlinear equations, the Jacobian matrices are constructed using numerical methods, which avoids artificial differences in complex mathematical formulas.

Model Conceptualization and Numerical Implementation

Because of the multi-component nature and multi-scale behaviors of shale rocks, we propose a multi-porosity, multi-physics model to quantify the key fluid flow behaviors in shale gas reservoirs, which consists of micro-scale fractures, small-or-intermediate-scale fractures, organic matters, and inorganic matters. Compared with the traditional method to simulate gas flow in shales, it is more realistic and physics-based. This model is an extension of the classical double-porosity model (Warren and Root, 1963) and other multiple-porosity model Wu et al., 2004; Yan et al., 2016). Similar to the concept of double-porosity model, it assumes that the thermodynamic equilibrium does not always exist between different flow media even at the same location, and therefore the key fluid-flow and thermodynamic properties (pressure, temperature, and concentration) are different (Wang, 2013; Wu et al., 2014). In addition, constitutive equations to describe relations between these physical quantities also vary as described above. The difference of storage mechanism is captured in the accumulation term in Equation (1.4):

$$M_{\alpha}^{\kappa} = \begin{cases} \phi \sum_{\beta} S_{\beta} \rho_{\beta} X_{\beta}^{\kappa}, & \alpha = \text{IOM} \\ \phi(\sigma_m) \sum_{\beta} S_{\beta} \rho_{\beta} X_{\beta}^{\kappa} + \rho_{\beta} V_L \frac{P}{P + P_L}, & \alpha = \text{OM} \\ \phi(\sigma_m) \sum_{\beta} S_{\beta} \rho_{\beta} X_{\beta}^{\kappa}, & \alpha = \text{NF, MF} \end{cases} \quad (1.5)$$

where the total mass of component κ in the accumulation term is obtained by summing over the fluid phases β . ϕ is porosity, sensitive to the mean stress σ_m for organic matter, intermediate-scale fractures, and micro fractures. S_{β} and ρ_{β} are the saturation and density of phase β , and X_{β}^{κ} is the mass fraction of component κ in phase β .

Similarly, advective mass flux is a sum over phases

$$F_{\alpha}^{\kappa} = - \sum_{\beta} X_{\beta}^{\kappa} \rho_{\beta} k_{a,\alpha} \frac{k_{r\beta,\alpha}}{\mu_{\beta}} (\nabla P_{\beta} - \rho_{\beta} \mathbf{g}) \quad (1.6)$$

where $k_{r\beta,\alpha}$ is the relative permeability to phase β , which varies in different flow continuum α as discussed above. μ_{β} is viscosity, and $k_{a,\alpha}$ is the apparent permeability.

$$k_{a,\alpha} = \begin{cases} k_{in} (1 + cK_n) \left(1 + \frac{4K_n}{1 - bK_n} \right), & \alpha = \text{IOM, OM} \\ k_{in}, & \alpha = \text{NF, MF} \end{cases} \quad (1.7)$$

Different governing equations for these various physical quantities, however, all follow the mass conservation law in general sense and thus can be handled uniformly under a general framework model. There is no need to modify previous discretization approaches, and the key challenge is to generate a mesh system for this framework that can capture these multi-porosity characteristics. Conceptually we decompose the complex and hierarchical rock structures into several continua, and each continuum represents a particular porous or fractured medium, as shown in Figure 4.

We further assume that fluid flow in the global domain is dominated by the connection of intermedia-scale fractures. Locally these intermedia-scale fractures connect to micro-scale fractures and inorganic matters. Gas stored in organic matter transports to production wells through inorganic matter, micro-scale fractures, and intermediate-scale fractures. The schematic of this multi-porosity conceptualization for handling multi-component nature and multi-scale behaviors of shale rocks is demonstrated in Figure 5, which can be

compared with the classical double-porosity model to conceptualize fracture-matrix interactions as shown in Figure 6.

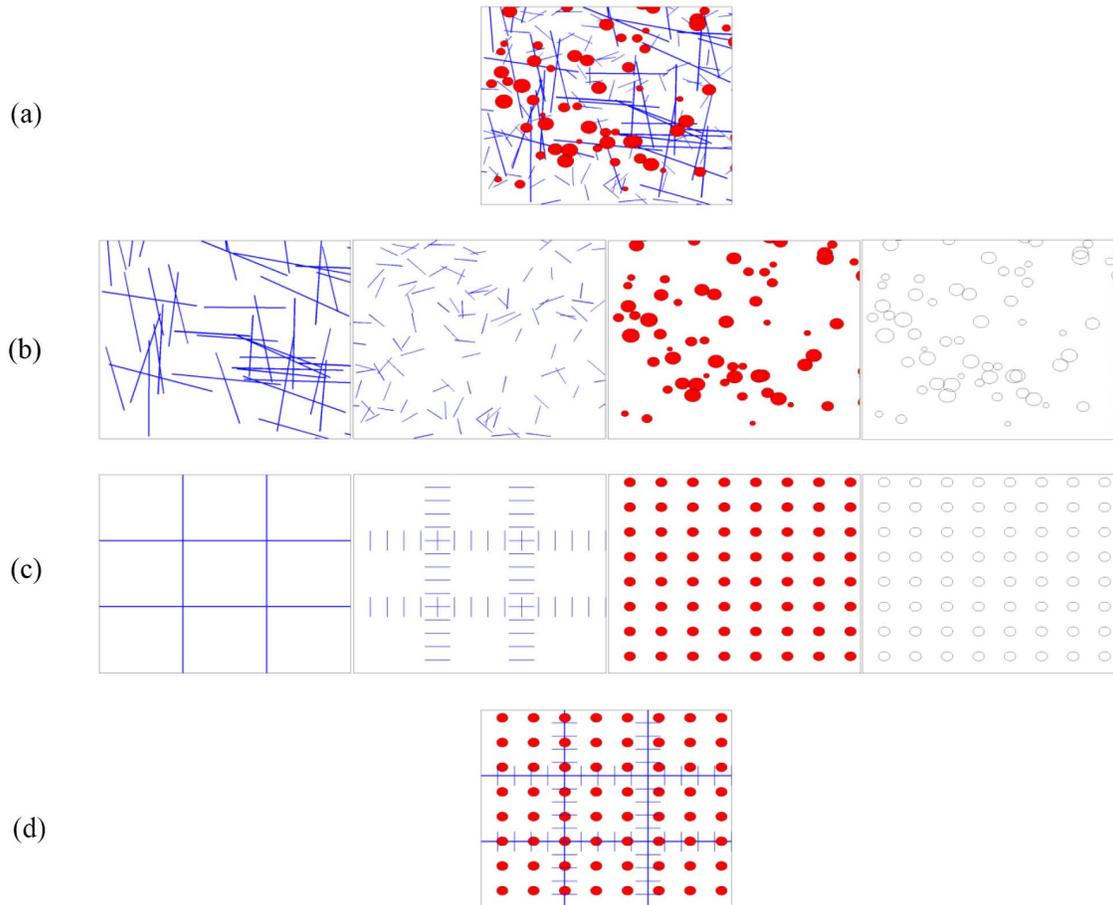


Figure 4—(a) General fracture network, organic and inorganic matter in shale rocks based on statistical distributions of fracture and porous medium properties, conceptualized from SEM image. (b) Decomposition of the complicated and hierarchical shale rock structure into multiple components (from left to right: natural fractures, micro fractures, organic matter, and inorganic matter). (c) Idealization of each component using the average approach by capturing the key flow characteristics. (d) Recombination of the idealized components for numerical simulation

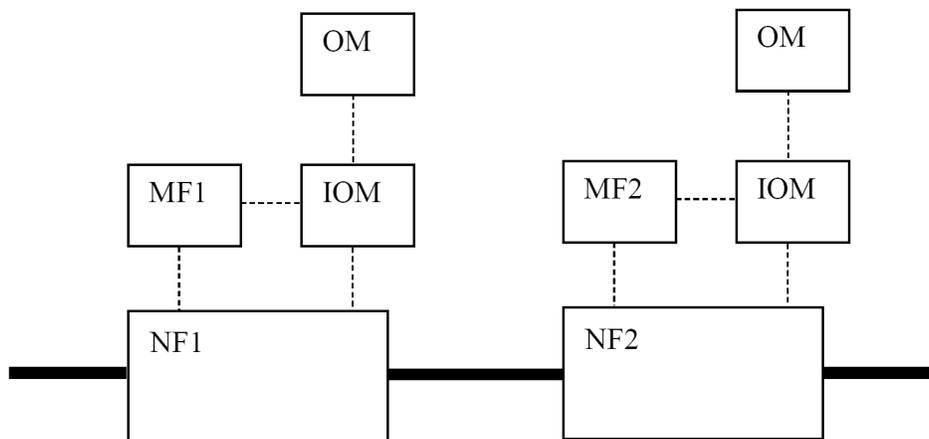


Figure 5—Schematic of multi-porosity conceptualization for handling multi-component nature and multi-scale behaviors of shale rocks

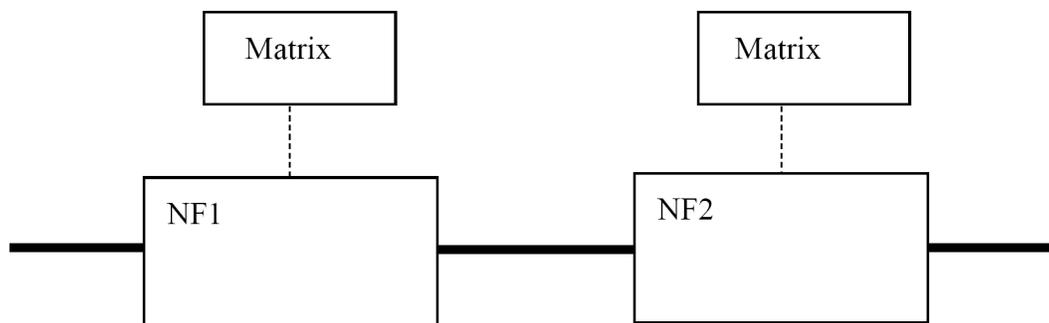


Figure 6—Schematic of classical double-porosity model to conceptualize fracture-matrix interactions

Numerically, these continua are characterized by several overlaid computational grid layers. In practice, each primary grid or single continuum grid is extended to multiple grids, which share the same location in the physical domain. Unlike the local grid refinement method (Yan et al., 2016), the connection information among these generated multi-grids is determined not just by geometrical information. These grids can be inter-connected within one continuum or intra-connected among different continuum according to the model assumption. Their connection parameters are obtained from geometric information and analytical solutions with the assumption of pseudo-steady state as shown in Table 1.

Table 1—Characteristic distances and contact area for evaluating flow terms in the multiple porosity system

3-D	NF-IOM	MF-IOM	NF-MF	IOM-OM
Characteristic Distances	$L_{\text{NF-IOM}} = \frac{l_{\text{NF}}}{10}$	$L_{\text{MF-IOM}} = \frac{l_{\text{MF}}}{10}$	$L_{\text{NF-MF}} = \frac{l_{\text{MF}}}{2}$	$L_{\text{IOM-OM}} = \sqrt{\frac{4\pi}{3\text{TOC}}} r_{\text{OM}}$

Note in Table 1, subscript NF represents intermediate-scale fractures, MF, micro-scale fractures, OM, organic matter, respectively. L is the characteristic distance, l is the fracture spacing, r is the radius of organic matter, TOC is the total organic content.

Note that in this model, the detailed microscopic flow geometry information is not all considered, and the complex microstructural composite system is represented by an average value. This average approach is practical and able to capture the key flow characteristics. Input parameters for this model (e.g., fracture density, total organic content, etc.) can be evaluated.

Model Application

In this section, we apply the proposed multi-porosity, multi-physics model to studying flow processes in a synthetic but realistic case. Attentions are given to potential differences caused by the proposed new model and the classical single-continuum and double continuum models. It presents a shale gas reservoir with horizontal well and multistage hydraulic fractures. The reservoir thickness is 20m. The half length of hydraulic fracture is 250m with fracture spacing of 40m. We assume that hydraulic fracture fully penetrates this formation and thus this 3D problem can be simplified into a 2D numerical model. We further assume the reservoir is symmetric along the horizontal well and hydraulic fractures. This way we can extract only one quarter of the area between two adjacent hydraulic fractures for simulation, while still can capture key flow characteristics. Figure 7 shows the schematic of the reservoir model, described above, and presents the mesh system for the extracted area with the corresponding hydraulic fractures. All the grid blocks have four porosities as discussed above, which include natural fractures, micro fractures, organic matter and inorganic matter, except that hydraulic fractures is simulated with single porosity medium with high permeability and porosity. The physical properties of different scale of fractures and matrix rock are summarized in Table 2.

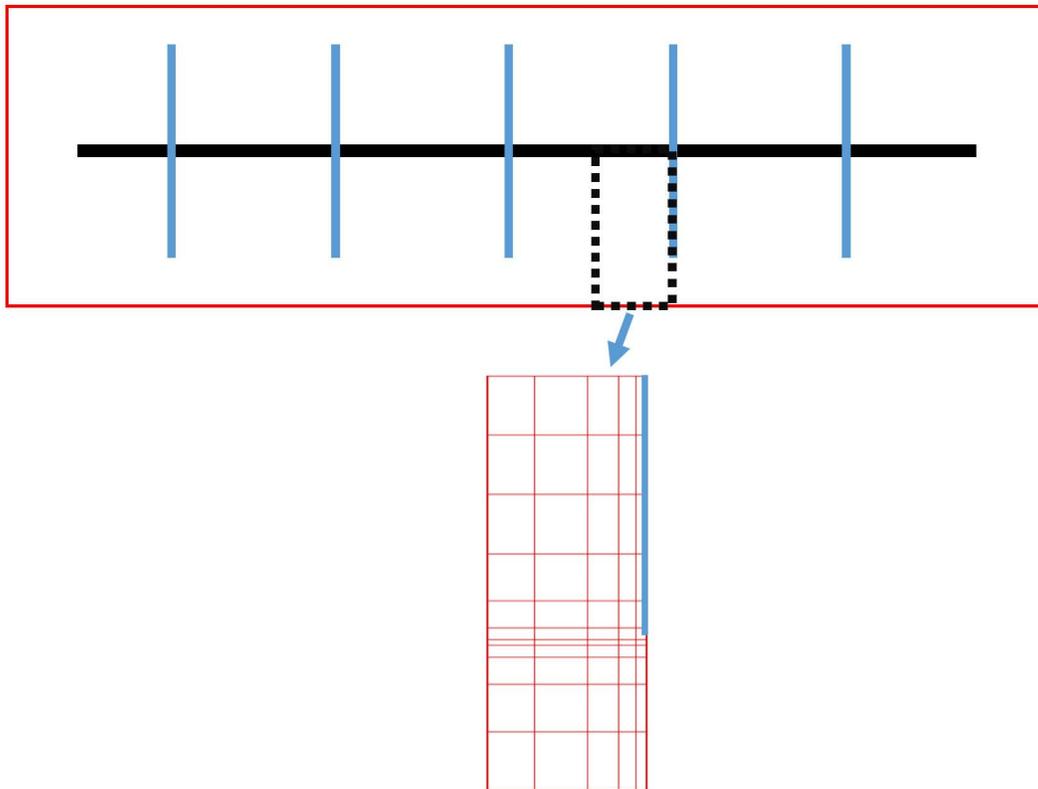


Figure 7—Schematic of the simulated reservoir model and mesh system for simulation with the corresponding hydraulic fractures

Table 2—The physical properties of different types of rocks

Parameters (Units)	Inorganic Matter	Organic Matter	Micro-Fracture	Natural Fracture
Permeability (m ²)	9.00E-19	6.00E-19	1.38E-15	1.38E-14
Porosity	0.05	0.25	0.01	0.001
Rock compressibility (1/Pa)	1.00E-09	2.00E-09	1.00E-08	1.00E-08
Klinkenberg coefficient (Pa)	8.60E+05	1.03E+06	0	0
Residual gas saturation	0.1	0.5	0	0
Irreducible water saturation	0.3	0	0	0
Adsorption parameter (m ² /kg)	0	2.20E-03	0	0

The initial reservoir pressure is assumed to be at 2.0×10^8 Pa. A constant production pressure is set to be 1.5×10^8 Pa and 10-year simulation is performed. Three simulation runs, single porosity model with equivalent porosity and permeability, double porosity model, and multiple porosity model, are compared. Figure 8 compares the normalized gas production rate from these three models. Only the multiple porosity model proposed in this paper could capture the typical production feature for a long time range: a great initial peak, a sharp decline in the first few months, followed by a long flat production tail. The single porosity model or double porosity model could only simulate certain time range of reservoir performance with acceptable accuracy, i.e., production rates drop towards zero and could not capture the long flat production tail for this case. The long flat production tail, or the slowdown of decline rate, in the later period of production is primarily due to the release of adsorbed gas, which is equivalent to an increase of gas compressibility (Wang and Wu, 2015). As introduced above, adsorption essentially happens at the surface

of the organic matter, which does not directly connect with the natural fractures. In the early time, gas is produced mainly from fractures and inorganic matters that connect to the fracture system. The pressure in organic matters remains relatively high. The free and adsorbed gas in organic matter begins producing only when a certain pressure difference occurs between the organic matter and inorganic matter. As shown in Figure 9, simulated pressure distributions for these four flow medium at the same time vary significantly. This way, the proposed model is able to capture the hierarchical characteristics of shale rocks.

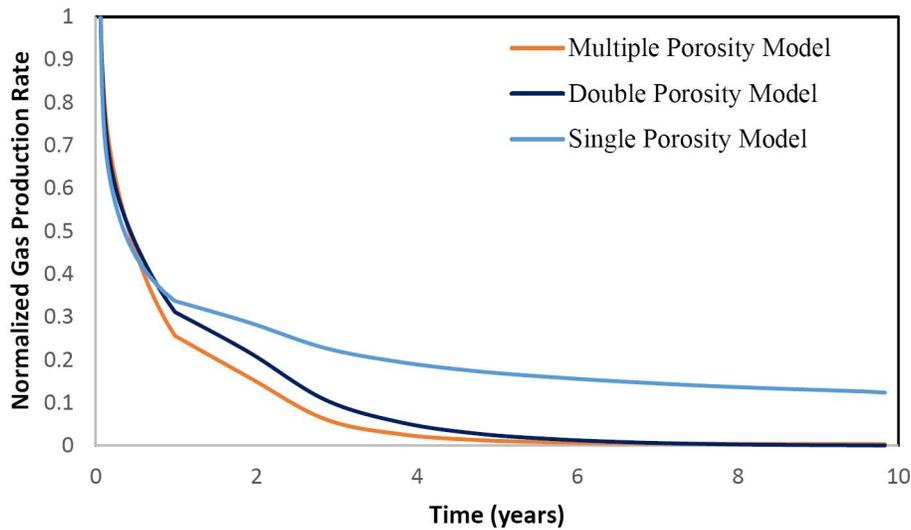


Figure 8—Comparison of gas production with three different simulation models

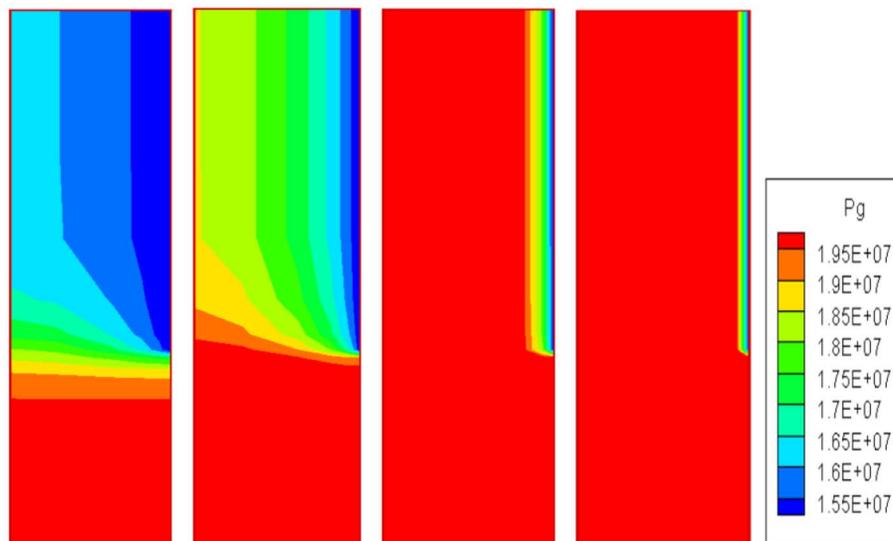


Figure 9—Simulated pressure distributions for these four flow medium at one year (from left to right: natural fractures, micro fractures, inorganic matter, and organic matter)

Summary

In this paper, we present a multi-domain, multi-physics model, aiming to accurately simulate the fluid flow in shale gas reservoirs with more physics-based flow models and formulations. The complicated and hierarchical shale rock structures are decomposed into five porosities: organic nanopores, inorganic nanopores, local micro-fractures, global natural fractures, and hydraulic fractures. Fluid flow governing equations in this model vary according to the different dominant fluid flow mechanism in different regions. We introduced a general numerical framework into which this model can be simply implemented. We also

discussed how to evaluate key parameters in setting up this numerical model. Model applications with practical interests are given. Several synthetic, but realistic, test cases are simulated. Our results demonstrate that this model is able to capture the typical production behavior of unconventional reservoirs: a great initial peak, the sharp decline in the first few months, followed by a long flat production tail.

Acknowledgments

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