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A Multiple-Continuum Approach for Modeling Multiphase Flow in Naturally Fractured Vuggy Petroleum Reservoirs

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Abstract

The existence of vugs or cavities in naturally fractured reservoirs has long been observed. Even though these vugs can be largely attributed to reserves of oil, natural gas, and groundwater, few investigations of vuggy fractured reservoirs have been conducted. In this paper, a new multiple-continuum conceptual model is developed, based on geological data and observations of core samples from carbonate formations in China, to investigate multiphase flow behavior in such vuggy fractured reservoirs. The conceptual model has been implemented into a three-dimensional, three-phase reservoir simulator with a generalized multiple-continuum modeling approach. The conceptual model considers vuggy fractured rock as a triple- or multiple-continuum medium, consisting of (1) highly permeable fractures, (2) low-permeability rock matrix, and (3) various-sized vugs. The matrix system may contain a large number of small or isolated cavities (of centimeters or millimeters in diameter), whereas vugs are larger cavities, with sizes from centimeters to meters in diameter, indirectly connected to fractures through small fractures or microfractures. Similar to the conventional double-porosity model, the fracture continuum is responsible for the occurrence of global flow, while vuggy and matrix continua, providing storage space, are locally connected to each other (and interacting with globally connecting fractures). For practical application of the multi-continuum concept in reservoir simulation, we propose a novel upscaling method for computing equivalent gridblock permeabilities of coarse blocks containing large isolated vugs, in which the local problems consisting of Darcy and Stokes flows are solved. In addition, we describe an efficient boundary condition for accurate computation of upscaled permeabilities. In the numerical implementation, a control-volume, integral finite-difference method is used for spatial discretization, and

a first-order finite-difference scheme is adapted for temporal discretization of governing flow equations in each continuum. The resulting discrete nonlinear equations are solved fully implicitly by Newton iteration. The numerical scheme is verified and applied to simulate water-oil flow through the fractured vuggy reservoirs of the Tahe Oil Field in China.

Introduction

Since the 1960s, investigation of flow and transport processes in fractured reservoirs has received much attention with significant progress being made. Driven by the increasing need to develop petroleum and geothermal reservoirs (as well as to resolve subsurface contamination problems), many numerical modeling approaches and techniques have been developed [6, 25, 15, 21]. The petroleum industry is currently facing a growing demand for oil and natural gas, while at the same time fewer new oil reserves exist worldwide. The efficient development of naturally fractured reservoirs, possessing a large portion of current world oil and gas reserves, has become a top priority. Thanks to the known low oil recovery rates from these reservoirs, interest in enhancing oil and gas recovery from such reservoirs has grown, with more investigations conducted for multiphase flow and transport phenomena in fractured reservoirs [2, 19, 4, 12]. Also, environmental concerns over subsurface contamination have motivated many related, similar studies [31, 26, 7].

Even though significant progress has been made towards understanding and modeling of flow and transport processes in fractured rock since the 1960s [6, 25, 15, 16, 21], most studies have focused primarily on naturally fractured reservoirs without taking into consideration of cavities. Recently, characterizing vuggy fractured rock has received attention, because a number of fractured vuggy reservoirs have been found worldwide that can significantly contribute to reserves and the production of oil and gas [17, 23, 18, 13, 9].

Mathematical approaches developed for modeling flow through fractured reservoirs rely in general on continuum approaches, involving developing conceptual models, incorporating the geometrical information of a given fracture-matrix system, setting up mass and energy conservation equations for fracture-matrix domains, and then solving discrete nonlinear algebraic equations of mass and energy conservation. The commonly used mathematical methods for modeling flow through fractured rock include: (1) an explicit discrete-fracture and matrix model [24], (2) a dual-continuum method, including double- and multi-porosity, dual-

permeability, or the more general "multiple interacting continua" (MINC) method [25, 16, 21], and (3) an effective-continuum method (ECM) [29].

In addition to the traditional double-porosity concept, a number of triple-porosity or triple-continuum models have been proposed [10, 33, 1, 5, 26, 14] to describe flow through fractured rocks. In particular, Liu et al. [18] and Camacho-Velazquez et al. [9] present several new triple-continuum models for single-phase flow in a fracture-matrix system that include cavities within the rock matrix (as an additional porous portion of the matrix). In general, these models have focused on handling the heterogeneity of the rock matrix or fractures, e.g., subdividing the rock matrix or fractures into two or more subdomains with different properties.

This study presents our continuing effort in developing the triple-continuum conceptual model [14], which attempts to include the effects of vugs and cavities on multiphase flow processes in naturally fractured vuggy reservoirs. In this model, vuggy fractured rock is conceptualized as a triple- or multiple-continuum medium, consisting of (1) highly permeable fractures, (2) low-permeability rock matrix, and (3) various-sized vugs. Similar to the conventional double-porosity model, the fracture continuum is responsible for global flow, while vuggy and matrix continua, providing storage space, are locally connected to each other (and interacting with globally connecting fractures). In the numerical implementation, a control-volume, integral finite-difference method is used for spatial discretization, and a first-order finite-difference scheme is adapted for temporal discretization of the governing flow equations in each continuum. The resulting discrete nonlinear equations are solved fully implicitly by Newton iteration. This numerical scheme is applied to simulate water-oil flow through the fractured vuggy reservoirs of the Tahe Oil Field in China.

Conceptual Model of Vuggy Fractured Formation

A typical fractured vuggy reservoir, as observed in a reservoir of carbonate formation in western China [34], consists of large-scale fractures, low-permeable rock matrix, and a large number of cavities or vugs. Those vugs and cavities are irregular in shape and vary in size (from millimeters to meters in diameter). Many small-sized cavities appear to be isolated from fractures. Figures 1(a), 2(a), and 3(a) summarize several conceptualizations, based on outcrops and cores from the reservoir fractured vuggy formation. Here we use "cavities" for small caves (millimeters to centimeters in diameter), whereas "vugs" represent larger cavities (with sizes from centimeters to meters in diameter). Figure 1(a) shows the typical characteristics of the main oil reserve or production layer of the reservoir, consisting of multi-scale fractures, various-sized isolated or connected (through fractures and small fractures) vugs and cavities, and rock matrix. Figure 1(b) conceptualizes the vuggy fracture system as a multi-continuum system of different-scale fracture networks, spatially varying vugs, cavities, and rock matrix. By comparison, Figure 2 presents features of discrete large fractures with few vugs, which connect to the fractures. Figure 3 shows a core sample with a large fracture and some partially

filled cavities. Several other conceptual models are discussed in Kang et al. [14] for the reservoir.

As shown in Figures 1, 2 and 3, the multi-continuum conceptual model considers large fractures as main pathways for the global flow. Vuggy and matrix continua, locally connected to each other as well as directly or indirectly interacting with globally connecting fractures, provide storage space as sinks or sources to fractures. Note that vugs directly connected with fractures (e.g., Figures 1, 2 and 3) could be considered part of the fracture continuum. More specifically, we conceptualize the fractured-vug-matrix system as consisting of (1) fracture continuum: "large" fractures (or fractures), *globally connected* on the scale of model domains, providing flow paths to injection and production wells; (2) vug continuum: various-sized vugs, which are *locally connected* to fractures either through "small" fractures or *isolated* by rock matrix; (3) matrix continuum: rock matrix, which may contain a number of cavities, *locally connected* to large fractures and/or to vugs; and (4), small-scale fractures (Figure 1) [26].

In principle, the proposed multiple-continuum model is a natural extension of the generalized multiple-continuum (MINC) approach [21, 32]. In this approach, an "effective" porous medium is used to an approximate fracture, vug, or rock matrix continuum, respectively. The triple- or multiple-continuum conceptual model assumes that approximate thermodynamic equilibrium exists locally within each of the continua at all times. Based on this local equilibrium assumption, we can define thermodynamic variables, such as pressure, fluid saturation, concentration, and temperature, for each continuum. Note that the multiple-continuum model is not limited to the orthogonal idealization of the fracture system, or uniform size, or distribution of vugs and cavities, as illustrated in Figures 1, 2, and 3. Irregular and stochastic distributions of fractures and cavities can be handled numerically, as long as the actual distribution patterns are known [22].

Mathematical Model

A fractured vuggy reservoir is assumed at isothermal conditions and composed of three phases: oil, gas, and water. For simplicity, the water and oil components are assumed to be present only in their associated phases, while gas may exist in both gas and oil phases. Each phase flows in response to pressure, gravitational, and capillary forces according to Darcy's law, while non-Darcy or tube flow may occur within connections between or inside vugs. Therefore, three mass-balance equations are needed to describe the multiphase flow system in an arbitrary flow region of the porous, fractured, and vuggy domain [14, 27]:

For gas flow,

$$\frac{\partial}{\partial t} [\phi(S_o \bar{\rho}_{dg} + S_g \rho_g)] = -\nabla \cdot (\bar{\rho}_{dg} \vec{V}_o + \rho_g \vec{V}_g) + q_g \quad (1)$$

For water flow,

$$\frac{\partial}{\partial t} (\phi S_w \rho_w) = -\nabla \cdot (\rho_w \vec{V}_w) + q_w \quad (2)$$

For oil flow,

$$\frac{\partial}{\partial t}(\phi S_o \bar{\rho}_o) = -\nabla \cdot (\bar{\rho}_o \bar{V}_o) + q_o \quad (3)$$

where when Darcy's law applies, the flow velocity of phase β ($\beta = g$ for gas, $= w$ for water, and $= o$ for oil) is defined as

$$\bar{V}_\beta = -\frac{k k_{r\beta}}{\mu_\beta} (\nabla P_\beta - \rho_\beta g \nabla D) \quad (4)$$

In Equations (1)-(4), ϕ is the effective porosity of the medium (fracture, vugs or porous matrix); ρ_β is the density of phase β at reservoir conditions; $\bar{\rho}_o$ is the density of oil, excluding dissolved gas, at reservoir conditions; $\bar{\rho}_{dg}$ is the density of dissolved gas (dg) in oil phase at reservoir conditions; μ_β is the viscosity of phase β ; S_β is the saturation of phase β ; P_β is the pressure of phase β ; q_β is the sink/source term of component β per unit volume of the medium, representing mass exchange through injection/production wells or resulting from fracture-matrix-vug interactions; g is gravitational acceleration; k is absolute/intrinsic permeability of the medium; $k_{r\beta}$ is relative permeability to phase β ; and D is depth.

Equations (1), (2) and (3), governing mass balance for three-phase flow, need to be supplemented with constraint equations and constitutive relations, which express all the secondary variables and parameters as functions of a set of key primary thermodynamic variables. In addition, capillary pressure and relative permeability relations are needed for each continuum, which are normally expressed in terms of functions of fluid saturations. The densities of water, oil, and gas, as well as the viscosities of fluids, can in general be treated as functions of fluid pressures.

Numerical Formulation

As discussed above, the governing equations for multiphase flow in fractured vuggy reservoirs have been implemented into a general-purpose, three-phase reservoir simulator, the MSFLOW code [30, 27]. As implemented numerically, Equations (1), (2), and (3) are discretized in space using an integral finite-difference or control-volume finite-element scheme for a porous-fractured-vuggy medium. Time discretization is carried out with a backward, first-order, finite-difference scheme. The discrete nonlinear equations for water, oil, and gas flow at node i are written as follows:

$$\left[(M_\beta)_i^{n+1} - (M_\beta)_i^n \right] \frac{V_i}{\Delta t} = \sum_{j \in \eta_i} F_{\beta,ij}^{n+1} + Q_{\beta i}^{n+1} \quad (5)$$

where M is the mass accumulation term of phase β ; superscript n denotes the previous time level; $n+1$ is the current time level; V_i is the volume of element i (porous, fractured, or vuggy gridblock); Δt is the time step size; η_i contains the set of neighboring elements (j) (porous, vuggy, or fractured) to which element i is directly connected; $F_{\beta,ij}$ is the mass flow term for phase β between elements i and j ; and $Q_{\beta i}$ is the mass sink/source term at element i of phase β .

The "flow" term ($F_{\beta,ij}$) in Equation (5) for multiphase Darcy flow between and among the multiple-continuum media, along the connection (i, j), is given by

$$F_{\beta,ij} = \lambda_{\beta,ij+1/2} \gamma_{ij} [\psi_{\beta j} - \psi_{\beta i}] \quad (6)$$

where $\lambda_{\beta,ij+1/2}$ is the mobility term to phase β , defined as

$$\lambda_{\beta,ij+1/2} = \left(\frac{\rho_\beta k_{r\beta}}{\mu_\beta} \right)_{ij+1/2} \quad (7)$$

Here subscript $ij+1/2$ denotes a proper averaging or weighting of properties at the interface between two elements i and j ; and $k_{r\beta}$ is the relative permeability to phase β . In Equation (7), γ_{ij} is transmissivity; when the integral finite-difference scheme [20] is used, γ_{ij} is defined as

$$\gamma_{ij} = \frac{A_{ij} k_{ij+1/2}}{d_i + d_j} \quad (8)$$

where A_{ij} is the common interface area between connected blocks or nodes i and j ; d_i is the distance from the center of block i to the interface between blocks i and j ; and $k_{ij+1/2}$ is an averaged (e.g., harmonically weighted) absolute permeability along the connection between elements i and j . The flow potential term in Equation (6) is defined as

$$\psi_{\beta i} = P_{\beta i} - \rho_{\beta,ij+1/2} g D_i \quad (9)$$

where D_i is the depth to the center of block i from a reference datum. The mass sink/source term at element i , $Q_{\beta i}$ for phase β , is defined as

$$Q_{\beta i} = q_{\beta i} V_i \quad (10)$$

In addition to multiphase Darcy flow, non-Darcy flow may also occur between and among the triple continua. A general numerical approach for modeling single-phase and multiphase non-Darcy flow [28] can be directly extended to the multiple-continuum model of this work. In general, flow along connecting paths of vugs through narrow pores or fractures may be too fast to describe using Darcy's law. In particular, when these vuggy connections could be approximated as a single fracture or a tube, the solutions of flow through a parallel-wall, uniform fracture or Hagen-Poiseuille [8] may be extended to describe such flow in (6) with

$$\lambda_{\beta,ij+1/2} = \left(\frac{\rho_\beta S_\beta}{\mu_\beta} \right)_{ij+1/2} \quad (11)$$

and

$$\gamma_{ij} = \frac{wb^3}{12(d_i + d_j)} \quad \text{for fracture connection} \quad (12)$$

$$\gamma_{ij} = \frac{\pi r^4}{8(d_i + d_j)} \quad \text{for tube connection} \quad (13)$$

where b is fracture aperture, w is fracture width, and r is tube radius. Note in (11), the saturation for an individual phase is used as the relative permeability of the phase. Similarly, flow solutions for both laminar and turbulent flow through simple

geometry of vug-vug connections can be used for flow between these vug connections.

Note that Equation (5) has the same form regardless of the dimensionality of the model domain, i.e., it applies to one-, two-, or three-dimensional analyses of multiphase flow through vuggy fractured porous media. In the numerical model, Equation (5) is written in a residual form and is solved fully implicitly using Newton/Raphson iteration.

Upscaling Method

For the multi-continuum approach, the computation of upscaled intrinsic permeability is required. For the fractures, these computations are somewhat well understood [11]. In particular, the effective coarse grid block permeability is computed from the solution of local flow problem. The boundary conditions of the local problem are such that the local flow has unit pressure gradient in each direction. These directional flows provide the values of upscaled permeability tensor. To avoid the effects of artificial boundary conditions, the boundary conditions can be imposed in the regions that are larger than the target coarse block. Furthermore, only the flow field in the target coarse block is used for the computation of upscaled permeability tensor. For the coarse regions containing vugs, we propose unit multi-physics problem for computing the upscaled permeabilities. This idea is first explored in Arbogast et al. [3]. The unit directional problem is set with pressure boundary conditions at the inlet and outlet and no flow boundary conditions on lateral sides. The local problem includes coupled Darcy and Stokes fluid flows. We propose the use of Brinkman equations or lattice Boltzman for the solution of the coupled flow problem. We have tested our results against resolved solution of coupled flow problem using standard multi-physics discretization techniques and found good agreement. The fact that the overall the coarse region can be described by Darcy's flow is proven using homogenization techniques [3]. In the computations, we employ oversampling techniques where a larger region (larger than the target coarse block) is chosen for the computation of local properties. Furthermore, the flow field only within the target coarse block is used for computing the effective grid block permeability. Based on orientation of vugs, we can also impose more accurate boundary conditions in order to capture the subgrid effects more precisely.

Handling Fracture-Vug-Matrix Interaction

The technique used in this work for handling multiphase flow through vuggy fractured rock follows the dual- or multiple-continuum methodology [25, 21, 33]. With this dual-continuum concept, Equations (1)–(4) can be used to describe multiphase flow along fractures and inside matrix blocks, as well as fracture-matrix-vug interaction. However, special attention needs to be paid to interporosity flow in the fracture-matrix-vug continua. Flow terms of interporosity between fracture-matrix, fracture-vug, vug-vug, and vug-matrix connections are all evaluated using Equation (6). However, the transmissivity of (8) will be evaluated differently for different types of interporosity flow. For fracture-matrix flow, γ_{ij} , is given by

$$\gamma_{FM} = \frac{A_{FM} k_M}{l_{FM}} \quad (14)$$

where A_{FM} is the total interfacial area between fractures (F) and the matrix (M) elements; k_M is the absolute matrix permeability; and l_{FM} is the characteristic distance for flow crossing fracture-matrix interfaces. For fracture-vug flow, γ_{ij} is defined as

$$\gamma_{FV} = \frac{A_{FV} k_V}{l_{FV}} \quad (15)$$

where A_{FV} is the total interfacial area between the fracture and vugs (V) elements; l_{FV} is a characteristic distance for flow between fractures and vugs; and k_V is the absolute vuggy permeability, which should be the permeability of small fractures that control flow between vugs and fractures (Figure 1). Note that for the domain in which vugs are isolated from fractures, as shown in Figure 1, no fracture-vug flow terms need to be calculated, because they are indirectly connected through the matrix.

For vug-matrix flow, γ_{ij} is evaluated as

$$\gamma_{VM} = \frac{A_{VM} k_M}{l_{VM}} \quad (16)$$

where A_{VM} is the total interfacial area between the vug and matrix elements; and l_{VM} is a characteristic distance for flow crossing vug-matrix interfaces. Similarly, the transmissivity between vugs, when they are connected through narrow fractures or tube can be defined.

Note that Table 1 [14] summarizes several simple models for estimating characteristic distances in calculating interporosity flow within fractures, vugs, and the matrix. In such cases, we have regular one-, two-, or three-dimensional large fracture networks, each with uniformly distributed small fractures connecting vugs or isolating vugs from fractures, based on the quasi-steady-state flow assumption of Warren and Root [25].

The MINC concept [22, 21] is extended to modeling flow through fractured-vuggy rock. In this approach, we start with a primary or single-continuum medium mesh that uses bulk volume of formation and layering data. Then, geometric information for the corresponding fractures and vugs within each formation subdomain is used to generate integrated finite-difference meshes from the primary grid. Fractures are lumped together into the fracture continuum, while vugs with or without small fractures are lumped together into the vuggy continuum. The rest is treated as the matrix continuum. Connection distances and interface areas are then calculated accordingly, e.g., using the relations discussed above and the geometric data of fractures and vugs. Once a proper mesh for a multiple-continuum system is generated, fracture, vuggy, and matrix blocks are specified, separately, to represent fracture or matrix continua.

In addition to the discretization techniques discussed above, the following assumptions may be also used: (1) there is equilibrium within vugs, i. e., no flow calculations are needed within vugs; (2) there is a noncapillary condition within vugs; and (3) relative permeability curves for flow from vugs to fractures and/or matrix are determined by fluid saturations in vugs based on complete mixing or gravitational segregation.

Model Verification and Application

The proposed numerical model formulation has been verified using analytical solutions [18, 26, 14]. The verification problem concerns typical transient flow towards a well that fully penetrates a radially infinite, horizontal, and uniformly vuggy fractured reservoir. Excellent agreement is obtained between the numerical and analytical solutions.

The numerical model is applied to simulate oil and water production in a selected fracture-vug unit of Region 4 of the Tahe Reservoir in western China. The geologic formation in Region 4 is typical of fractured, vuggy rock, and oil reserves are mainly contained within the pore space of fractures and varying-sized cavities or vugs. The reservoir conditions and parameters are as follows: formation temperature is at 121°C; initial pressure is 595.8 bars; crude oil viscosity is 3.4 cp; STC oil density is 0.88 g/cm³; original oil formation volume factor is 1.1; oil compressibility is 8.1×10^{-9} /Pa; water compressibility is 1.0×10^{-10} /Pa; and water density is 1.0 g/cm³. Oil production started in 1997 and reached its peak of production in 2000.

A three-dimensional (3-D) numerical grid is generated to simulate this production unit, with Figure 4 showing a plan view of the 3-D grid and the horizontal domain of the unit formation. The grid uses uniform gridblocks, with 45 columns in the x direction and 60 rows in the y direction. Vertically, the reservoir domain is subdivided into 16 geological layers (See Table 1), which are discretized into 30 numerical grid layers of varying thickness.

Table 1 lists the geological and grid layers with rock properties used for the field simulation example. The rock properties were estimated from core, well-log, and other geophysical data. The formation consists of four rock types: (1) ROCK1 for unfilled vug rock, (2) ROCK2 for partially filled vug rock; (3) ROCK3 for fully filled vug rock; and (4) DENSE for the tight and low-permeability layers, which behaves as an aquitard, allowing only vertical flow between oil-production layers. Figure 5 presents a 3-D view of the fractured vuggy formation.

Figure 6 shows an example of the simulated 2006 oil saturation distributions within the Region 4 unit of the Tahe Oil Field, after history matching. It is found that model results reasonably match measured saturation data and water-cut data, as well as original oil saturations.

Summary and Concluding Remarks

A physically based conceptual and numerical model is presented that simulates multiphase flow through vuggy fractured rock using a multiple-continuum medium approach. The suggested multiple-continuum concept is a natural extension of the classic double-porosity model, with the fracture continuum responsible for conducting global flow, while vuggy and matrix continua, locally connected and

interacting with globally connecting fractures, provide storage space for fluids.

The proposed conceptual model has been implemented into a general multidimensional numerical reservoir simulator using a control-volume, finite-difference approach, which can be used to simulate single-phase as well as multiple-phase flow in 1-D, 2-D and 3-D reservoirs. Model verification studies were reported in a previous study, and more simulation studies of actual vuggy-fractured petroleum reservoirs are under way.

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Table 1. Geological and grid layers and rock properties used for the field simulation example

Layer	Top Depth (ft)	Bottom depth (ft)	Thickness (ft)	Fracture Porosity (%)	Vug-cavity Porosity (%)	Oil saturation(%)	Rock type
1	5346.1	5347.4	1.3	0.08	26.55	88.48	ROCK1
2	5347.4	5356.5	9.1	0.00	0.00	0.00	DENCE
3	5356.5	5372.4	15.9	0.35	4.57	71.33	ROCK2
4	5372.4	5401.3	28.9	0.00	0.00	0.00	DENCE
5	5401.3	5414.8	13.5	0.15	1.21	60.00	ROCK3
6	5414.8	5429.8	15	0.16	1.01	72.27	ROCK3
7	5429.8	5430.9	1.1	0.00	0.00	0.00	DENCE
8	5430.9	5438.2	7.3	0.10	1.21	65.62	ROCK3
9	5438.2	5440.9	2.7	0.00	0.00	0.00	DENCE
10	5440.9	5446.6	5.7	0.08	0.78	60.00	ROCK3
11	5446.6	5447.6	1	0.00	0.00	0.00	DENCE
12	5447.6	5455.5	7.9	0.33	1.62	68.20	ROCK3
13	5455.5	5457.1	1.6	0.00	0.00	0.00	DENCE
14	5457.1	5465.8	8.7	0.29	7.39	84.98	ROCK1
15	5465.8	5500	34.2	0.00	0.00	0.00	DENCE
16	5500	5550	50	0.10	7.00	0.00	ROCK2

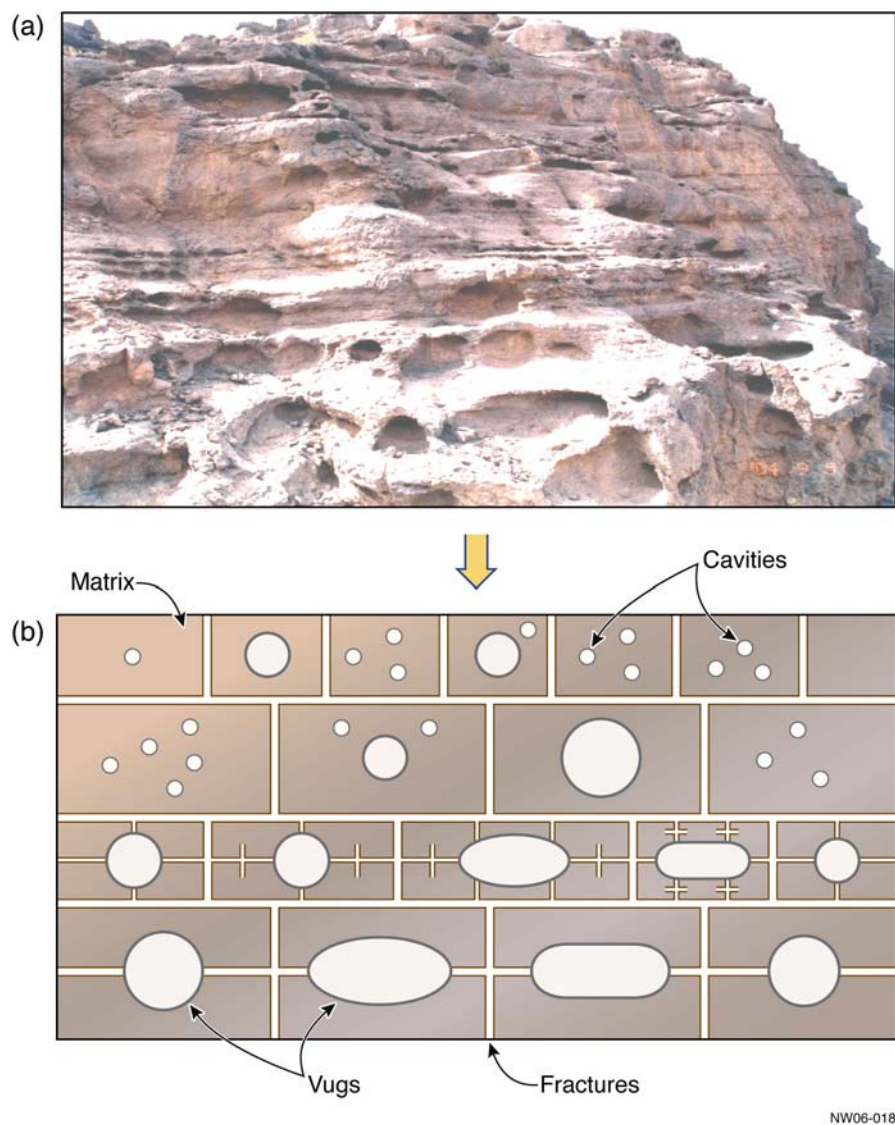
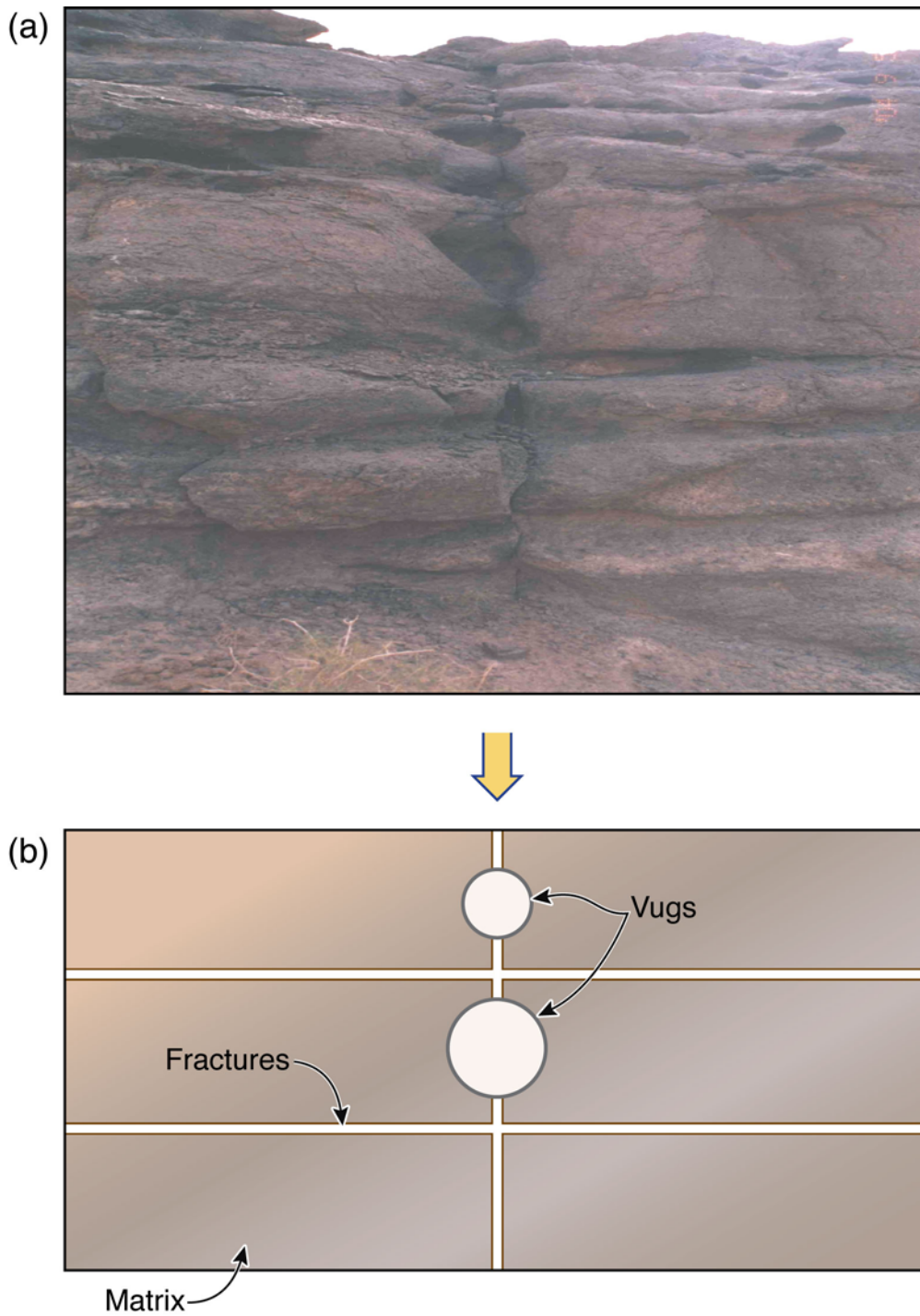


Figure 1. Schematic of conceptualizing vuggy fractured formation as a multiple-continuum system with different-scale fractures, various vugs and cavities; (a) outcrop pictures and (b) conceptual model



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Figure 2. Schematic of conceptualizing vuggy fractured formation as a discrete fracture system with well connected, (a) outcrop pictures and (b) conceptual model

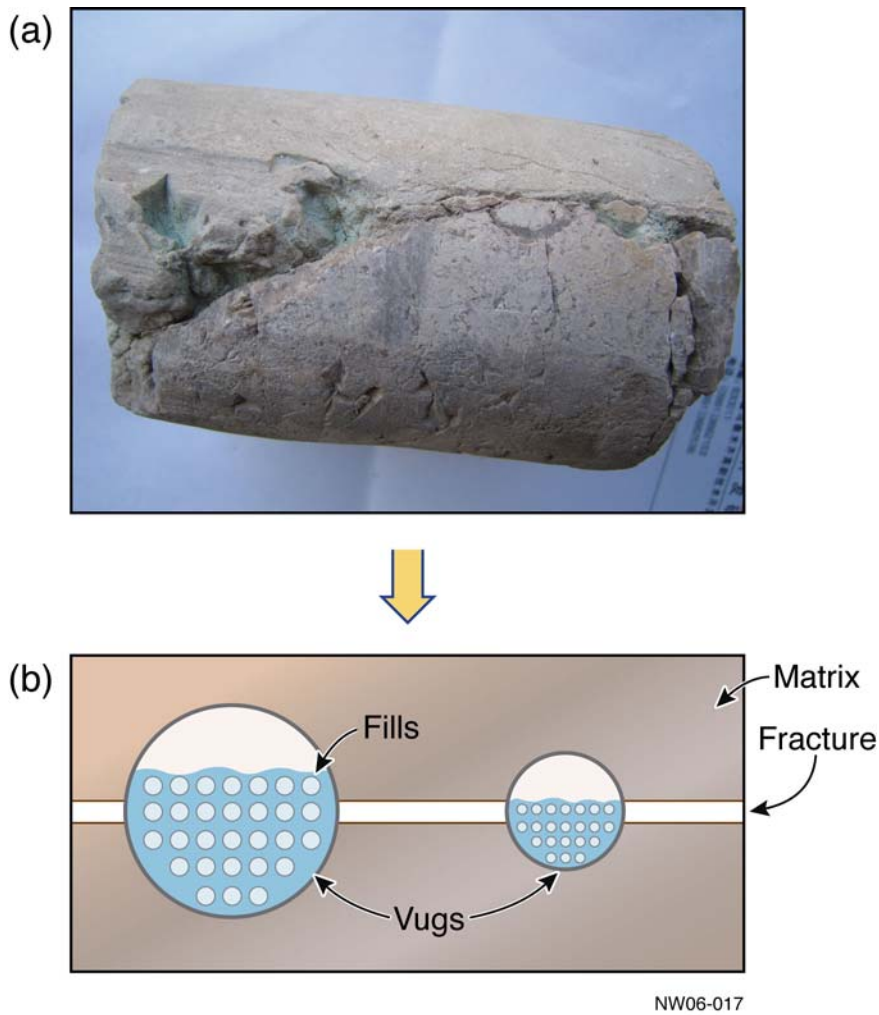


Figure 3. Schematic of conceptualizing vuggy fractured formation as a fracture-vug-matrix system with well partially filled vugs, (a) core sample and (b) conceptual model

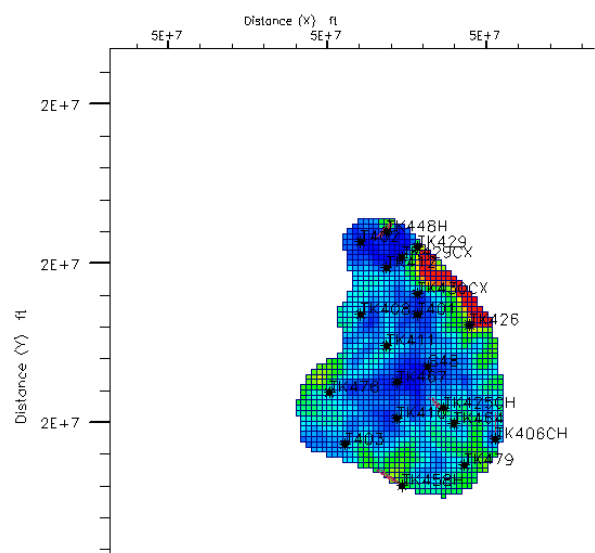


Figure 4. Plan view of the 3-D numerical grid used in the simulation of Region 4 of the Tahe Oil Field

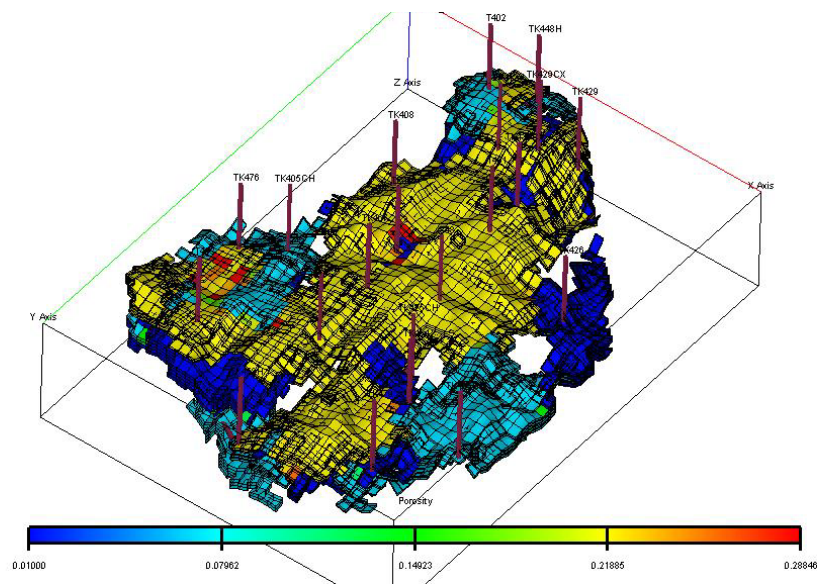


Figure 5. A 3-D View of the fractured vuggy system of Region 4 of the Tahe Oil Field

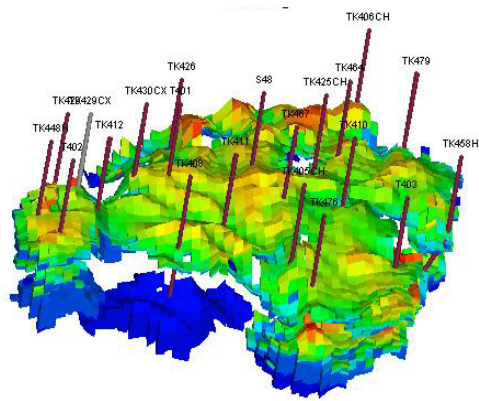


Figure 6. 2006 Distribution of simulated oil saturations within Region 4 of the Tahe Oil Field