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Research Article

A New Method for Calculating the Cementation Exponent of Triple-Porosity Media Reservoirs

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The value of a cementation exponent, usually obtained by rock and electricity experiments, significantly affects the calculation of water saturation, thickness of the hydrocarbon reservoir, and recovery rate. The determination of the cementation exponent for porous-media reservoirs has been a challenge because of the limited core sampling. A new method was proposed to determine the value of cementation exponent for complex triple-porosity media reservoirs in the work. Firstly, the work discussed the effects of fractures and nonconnected vugs on the cementation exponent of the reservoir as well as the calculation method of the cementation exponent of the dual-porosity media reservoir. Then, a new model for calculating the cementation exponent of triple-porosity media reservoirs was derived by combining the Maxwell-Garnett theory and series-parallel theory, which matched with the real physical-experiment data of rocks. The results showed that the fractures decreased the cementation exponent of the reservoir but the vugs increased. The mixture of matrix pores, fractures, and vugs made the value of the cementation exponent of the triple-porosity media reservoir vary around 2.0. The conductivity of the triple-porosity media reservoir was the external macroscopic expression of the microscopic conductive network. The new calculation model of the cementation exponent proposed in the work could reasonably predict the cementation exponent of the strongly inhomogeneous triple-porosity media reservoir.

1. Introduction

With the development of the world's oil and gas exploration, the oil and gas reserves and output obtained in fractured-vuggy reservoirs have become larger and larger. In the past decades, the petrophysical analysis of the triple-porosity media reservoirs with fractures and vugs has been a hot spot in the oil and gas industry. For the reservoir with serious heterogeneity and complex pore structure [1], the application of Archie's equation is limited due to the significant difference in porosity indices for different reservoirs. The complexity of the pore structure dramatically enlarges the range of the pore structure exponent in the Archie equation and affects the solution of water saturation. People have been exploring the calculation methods and value of cementation exponent (porosity index) m of the triple-porosity reservoirs adapted to the complex pore structure to improve the application of Archie's equation.

m is the cementation index of the reservoir, also known as the porosity index, reflecting the cementation of the reservoir, pore-throat tortuosity, and fracture opening, especially for the connectivity of pores. Its physical significance is to characterize the influence of the pore structure (microscopic characteristics of the reservoir space) on the conductivity of the rock. m is the slope of the relationship between formation-resistivity factor F and porosity Φ in the logarithmic coordinate system. The changes in F of sandstone reservoirs with porosity are relatively consistent, but the influence of the changes in permeability on F is not apparent, especially in the case of low permeability [2]. In a triple-porosity media reservoir, the distribution and variation of cementation exponent m of the reservoir is a geometric parameter, which is mainly controlled by three different pore types (matrix pores, fractures, and vugs) and their coupling relationship.

Towle [3] noticed the variation of pore index m in Archie's equation. For reservoirs with vugs, the m value is between 2.67 and 7.3, while for the reservoirs with fractures, that is less than 2, and the matrix porosity is 0 in the Towle model. Aguilera [4] introduced a dual-porosity model that can handle matrix and fracture pores, considering three different Archie cementation indices: matrix (m_b), fracture ($m_f = 1$), and the combined index of the two (m). The dual-porosity model proposed by Rasmus [5] considers the change of fracture curvature, but this model causes m to be greater than m_b, with the increased total porosity. Rasmus [6] used the Maxwell-Garnett theoretical model to establish the relationship between formation resistivity factor F and porosity Φ of a two-porous system with vugs and fractures and intergranular pores as the matrix. Karst caves increase the cementation index of the reservoir, while fractures reduce the cementation index of the reservoir.

Serra [7] established a model suitable for fractures and unconnected vugs to plot the relationship between porosity exponent m and the total porosity. Aguilera [8] improved the Serra model, showing that a more suitable equation should include matrix porosity Φ_b related to the total volume of the matrix system. According to the series-parallel connection method, an equation for calculating the m value is derived [8], which is suitable for the dual pore system of the matrix and fractures or the matrix and unconnected vugs. Aguilera [9] proposed a triple-porosity model suitable for the matrix, combining fractures and unconnected vugs. Berg [10] developed a new m-value calculation method of the triple-porosity model using effective medium theory to derive the dual-porosity equation.

Olusola et al. [11] developed a unified equation for electromagnetic mixing rules, which is used to calculate the m value of dual-porosity or triple-porosity reservoirs (systems). Besides, Berg's new three-porosity model method is used. C. Aguilera and R. Aguilera [12] considered the influence of fracture dip on porosity exponent m. Al-Ghamdi et al. [13] improved Aguilera's triple-porosity model by strictly treating the scales associated with each matrix, fracture, and vug. Piedrahita and Aguilera [14] established a dual-porosity analysis model to quantitatively calculate secondary mineralization (cementation) and tortuosity in natural fractures. If the influences of matrix, fractures, and vugs are not taken into consideration, it may lead to errors in selecting the m value. Then, significant errors occur in calculating water saturation, the thickness of oil and gas reservoir, and recovery factor.

The previous petrophysical experiments and theoretical models are beneficial, but they are not practical enough to obtain the m value of a triple-porosity medium reservoir with serious heterogeneity. The work focused on determining the value of cementation exponent m of the triple-porosity media reservoirs (such as carbonate) with pores, fractures, and vugs.

2. Materials and Methods

The intense chemical and biological actions of carbonate rocks cause the uneven salinity distribution of formation water, the tortuous and bifurcated conductive path, and the apparent nonlinear characteristics [15]. Many factors influence m, such as porosity, pore-throat size, type of rock particles, type and distribution of clay content, degree of cementation, and overburden pressure [16, 17]. All these are controlled by sedimentation, tectonics, and diagenesis. The storage space (pore structure) of the reservoir is the primary manifestation of the three control effects.

Lucia [18] adopted an improved version of Dunham's classification, dividing the fabrics into grain-based and argillaceous-based so that the geological classification is compatible with petrophysical classification. Pores are divided into intergranular pores and vuggy porosity. Intergranular porosity is commonly mentioned as matrix porosity by reservoir engineers. Vuggy porosity is divided into independent vugs (referred to as nonconnected vugs) and contacted vugs (referred to as connected vugs). In the three-porosity model of carbonate reservoir, Pores are divided into matrix pores, fractures, and nonconnected vugs. The traditional Archie equation and understanding are based on the sandstone reservoir with homogeneity and single pore structures. It is a regular fitting of experimental data of core resistivity [19]. Since the carbonate reservoir is seriously heterogeneous and anisotropic, the pore structure is no longer single but a complex triple-porosity medium with intergranular pores, natural fractures, and cave storage spaces. Therefore, the conductive path is also highly complicated. In the petrophysical experiments, it is difficult to obtain a complete core in fractures and vugs, which causes errors between the laboratory-measured value and the actual m value of the triple-porosity media reservoirs (see Figure 1).

For serious heterogeneous triple-porosity media reservoirs such as carbonate rocks, traditional petrophysics experiments are limited in understanding due to the artificial selection of core samples. As a result, the electrical characteristics of reservoir rock cannot be fully understood [20]. Especially in low-porosity formations, the relationship between electrical conductivity and porosity is more complicated, and pore-throat ratio, tortuosity, and connectivity are three important influencing factors [21]. The combination of the theoretical model and simulation can provide insights into how the microscopic petrophysical properties affect the macroscopic conductivity of porous media [22]. It is especially true for triple-porosity medium carbonate reservoirs with simultaneous development of vugs and fractures (see Figure 1). Therefore, the work discussed the m-value calculation method of dual-porosity media reservoirs and the influence of fractures and caves on the m value of the reservoir and then proposed the new calculation method of the m value of triple-porosity media reservoirs with pores, fractures, and vugs of reservoir space.

2.1. Calculation of the Value of Cementation Exponent m of Dual-Porosity Media Reservoirs with Matrix Pores and Nonconnected Vugs. Sen et al. [23] used a Maxwell-Garnett mathematical relationship to simulate the current performance of mixtures of rock particles and water. Kenyon and Rasmus [24] used these expressions to simulate the low-frequency conductivity and high-frequency dielectric measurement of oolitic limestone (with large spherical

(a) (b) (c) (d)

Figure 1: Core sampling of the petrophysical experiment: (a) reservoir with matrix pores, (b) reservoir with matrix pores and fractures, (c) reservoir with matrix pores and vugs, and (d) reservoir with matrix pores, fractures, and vugs.

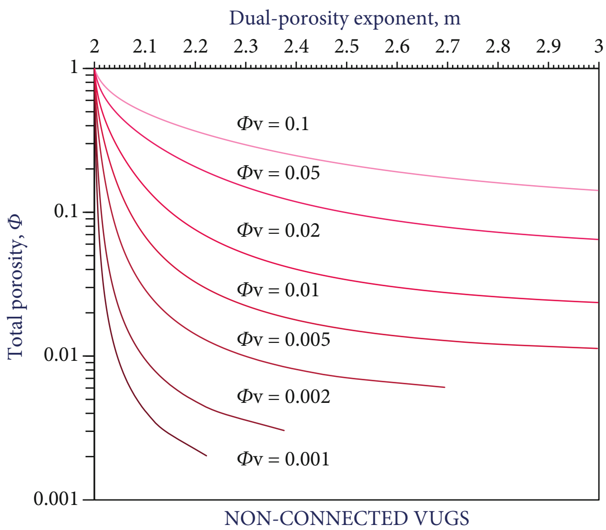

Figure 2: m determined as a function of dual-porosity media reservoirs with only matrix pores and nonconnected vugs ($m_b = 2$) [6].

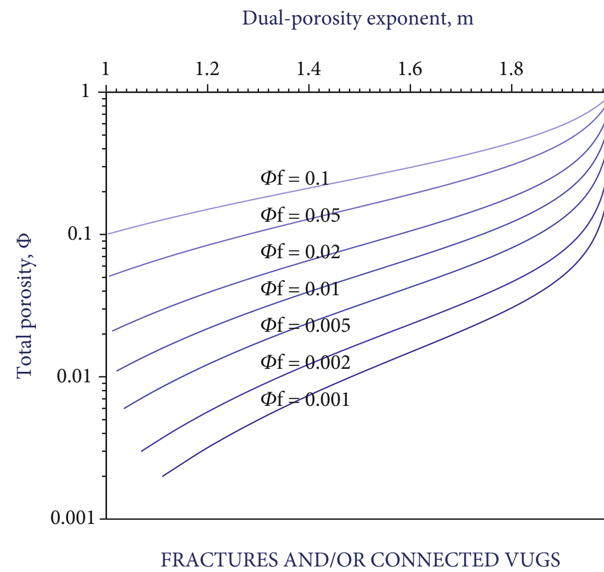

Figure 3: m determined as a function of dual-porosity media reservoirs with only matrix pores and fractures (or connected vugs) ($m_b = 2$) [8].

secondary pores and intergranular pores). Besides, they presented the low-frequency conductivity response (inductive or lateral) of a mixture of water-filled spherical pores embedded in a host material (matrix). Rasmus [6] simulated the influence of karst caves on formation resistivity factor F according to the Maxwell-Garnett mathematical relationship and plotted the relationship between F and total porosity (the fraction of intergranular pore volume and secondary pore volume). The larger spherical secondary pores in the oolitic limestone can be regarded as vugs because they are much larger than the intergranular pores. The mathematical form proves that cementation exponent m of the reservoir with the dual-porosity system (intergranular pores and vugs) will become larger because of vugs.

The low-frequency conductivity response (the reciprocal of resistivity) deduced by Rasmus, the Maxwell-Garnett equation, and the Archie equation are used to derive the equation of the m value of the dual-porosity-system reservoir composed of the matrix with intergranular pores and nonconnected vugs [6] (see Equation (1)).

$$m = \frac{\lg\left\{\phi_b^{mb}\left[\left(1+2\phi_v-2\phi_b^{mb}(\phi_v-1)\right)/\left(\phi_b^{mb}(2+\phi_v)+1-\phi_v\right)\right]\right\}}{\lg\phi}. \tag{1}$$

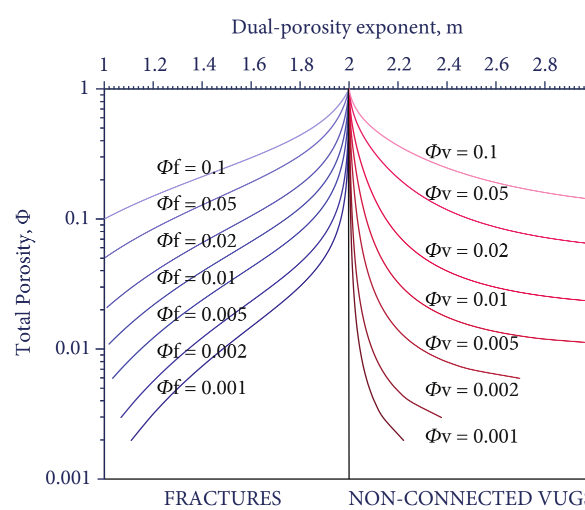

Figure 4: Influences of fractures [8] and nonconnected vugs [6] on the m value of the reservoir.

According to Equation (1), the relationship between the total porosity and cementation exponent m of the dual-porosity media system of matrix pores and nonconnected

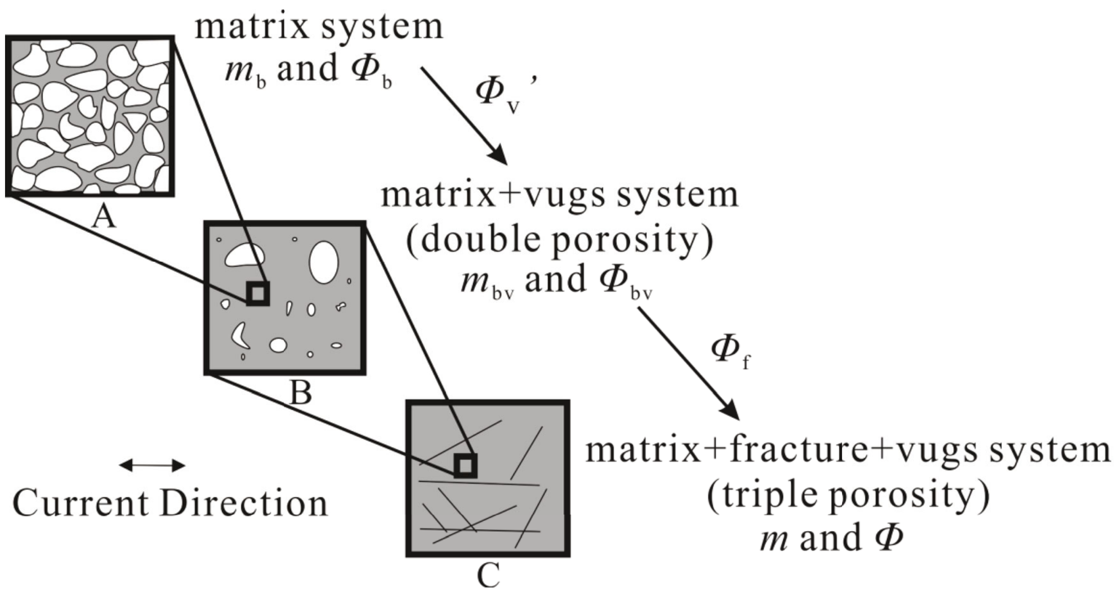

Figure 5: Calculation model and process of the m value of the triple-porosity composite system modified according to the Berg [10] calculation model.

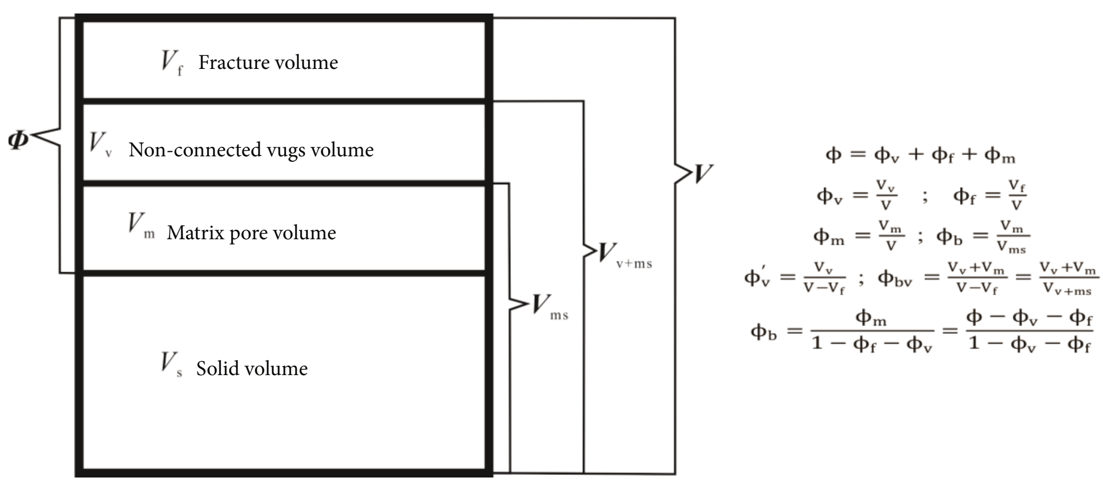

Figure 6: Petrophysical volume model of the triple-porosity medium composite system [20].

vugs is presented (see Figure 2), showing that the cementation exponent of the dual-porosity media system is greater than 2 because of vug porosity [6]. As the vug porosity increases, the m value of the dual-porosity system increases.

2.2. Calculation of the Value of Cementation Exponent m of Dual-Porosity Media Reservoirs with Matrix Pores and Fractures (or Connected Vugs). Aguilera [8] modeled a reservoir with matrix porosity and fracture porosity (or a reservoir with matrix porosity and connected vugs) as a parallel resistance network. The Φ_b value corresponds to the matrix porosity, equaling to the pore space in the matrix divided by the volume of the matrix system [8]. It modifies the misconception that the matrix porosity Φ_b in the m-value calculation model of Serra [7] is attached to the volume of the composite system. Φ represents the total porosity (matrix+fractures or matrix+connected vugs) of the reservoir, and a calculation model for the m value of a dual-porosity reservoir composed of the matrix and fractures is obtained.

Rasmus [5] placed the fracture volume in parallel with a limestone volume containing matrix pores and the resistivity-responding model of the limestone containing intergranular porosity with fractures embedded within. Besides, the equation to calculate the m value is derived based on the parallel connection of the fractures and matrix. The equation includes the parameter of fracture curvature. This model is advantageous, but the parameter of fracture curvature should be smaller when the total porosity increases. Otherwise, it will cause the problem of $m > m_b$. Rasmus simulated the influence of fractures on the formation resistivity factor F and plotted it as a function of total porosity (matrix porosity and fracture porosity). m decreases as fracture porosity increases, following the conclusion of Aguilera [8]. Equation (2) shows the m value in a dual-porosity system with intergranular pores and fractures, developed by Aguilera [8].

$$m = \frac{\lg\left[\phi_\mathrm{f} + \phi_\mathrm{b}^{\mathrm{mb}}(1-\phi_\mathrm{f})\right]}{\lg \phi}. \quad (2)$$

Equation (2) [8] is used to plot the relationship between the total porosity and cementation exponent m of the matrix and fracture dual-porosity system (see Figure 3). The cementation indices of the dual-porosity system are less than two due to fracture porosity. As fracture porosity increases, the m value of the dual-porosity system decreases.

2.3. Calculation of the Value of Cementation Exponent m of Triple-Porosity Media Reservoirs (Matrix Pores-Fractures-Vugs). Developed fractures in a three-porosity medium reservoir reduce the m value of the reservoir, and the developed vugs increase the m value of the reservoir. It shows the influence of fractures and nonconnected vugs on the m value of the reservoir (see Figure 4). However, triple-porosity medium reservoirs such as carbonate reservoirs often develop matrix pores, fractures, and vugs. The combination of the three types of storage spaces is complex and diverse. The rock matrix and the three types of storage spaces exist like the network. Current often flows along the path of minimum conductance, and the actual conductive path is more complex than that of the theoretical model.

The conductivity mechanism of the macroscale triple-porosity media reservoir is the coexistence and interaction of several equivalent conductivity models. The resistivity of the triple-porosity media reservoir is the macroscopic distribution of the micro series-parallel network system. Aguilera [9] deduced the equation for calculating the m value of carbonate reservoir with three porosity media combinations of matrix pores, fractures, and vugs. Matrix pores are used to connect with fractures in parallel, and then, the combination of matrix pores and fractures is utilized to connect in series with nonconnected vugs.

For triple-porosity media reservoirs with pores, fractures, and vugs, the calculation method of the m value for triple-porosity media reservoirs developed in the work is to follow the calculation method of Berg's triple-porosity model [10]. After obtaining total porosity Φ_bv of the dual-porosity system of matrix and vugs in the triple-porosity system, Φ_bv and $\Phi_\mathrm{v}{}'$ are introduced into the Maxwell-Garnett theoretical relationship to calculate the cementation exponent of the dual-porosity media system with the matrix and vugs [6] in triple-porosity media composite system m_bv. Then, block cementation exponent m_b and block pores Φ_b in the dual-porosity media system with the matrix and fractures are replaced with cementation exponent m_bv and total porosity Φ_bv of the dual-porosity system with the matrix and vugs. Finally, the Aguilera equation [8] was used to calculate the cementation exponent of the dual-porosity media system with the matrix and fractures and was simplified to obtain Equation (3) for calculating the m value of triple-porosity media reservoirs.

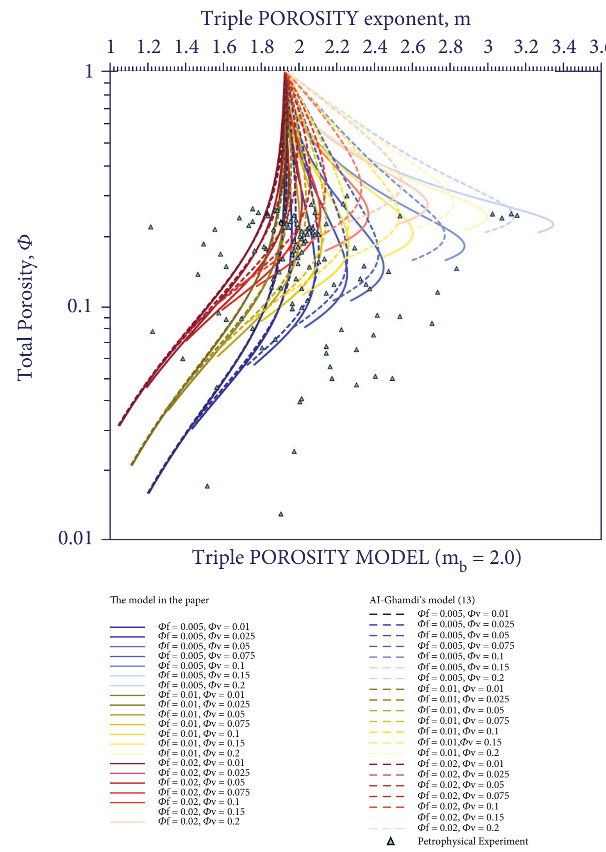

Figure 7: m determined as a function of triple-porosity media reservoirs with matrix pores, fractures, and vugs ($m_\mathrm{b} = 2.0$). The experimental data comes from Ragland [17].

$$m = \frac{\lg\left\{\phi_\mathrm{f} + (1-\phi_\mathrm{f})\left[(\phi_\mathrm{v} + \phi_\mathrm{b}(1-\phi_\mathrm{v}-\phi_\mathrm{f}))/(1-\phi_\mathrm{f})\right]^{\lg\left\{\phi_\mathrm{b}^{\mathrm{mb}}\left(\left(1+2\phi_\mathrm{v}-\phi_\mathrm{f}+2\phi_\mathrm{b}^{\mathrm{mb}}(1-\phi_\mathrm{v}-\phi_\mathrm{f})\right)/\left(\phi_\mathrm{b}^{\mathrm{mb}}(2-2\phi_\mathrm{f}+\phi_\mathrm{v})+1-\phi_\mathrm{v}-\phi_\mathrm{f}\right)\right)\right\}/\lg\left\{(\phi_\mathrm{v}+\phi_\mathrm{b}(1-\phi_\mathrm{v}-\phi_\mathrm{f}))/(1-\phi_\mathrm{f})\right\}}\right\}}{\lg \phi} \quad (3)$$

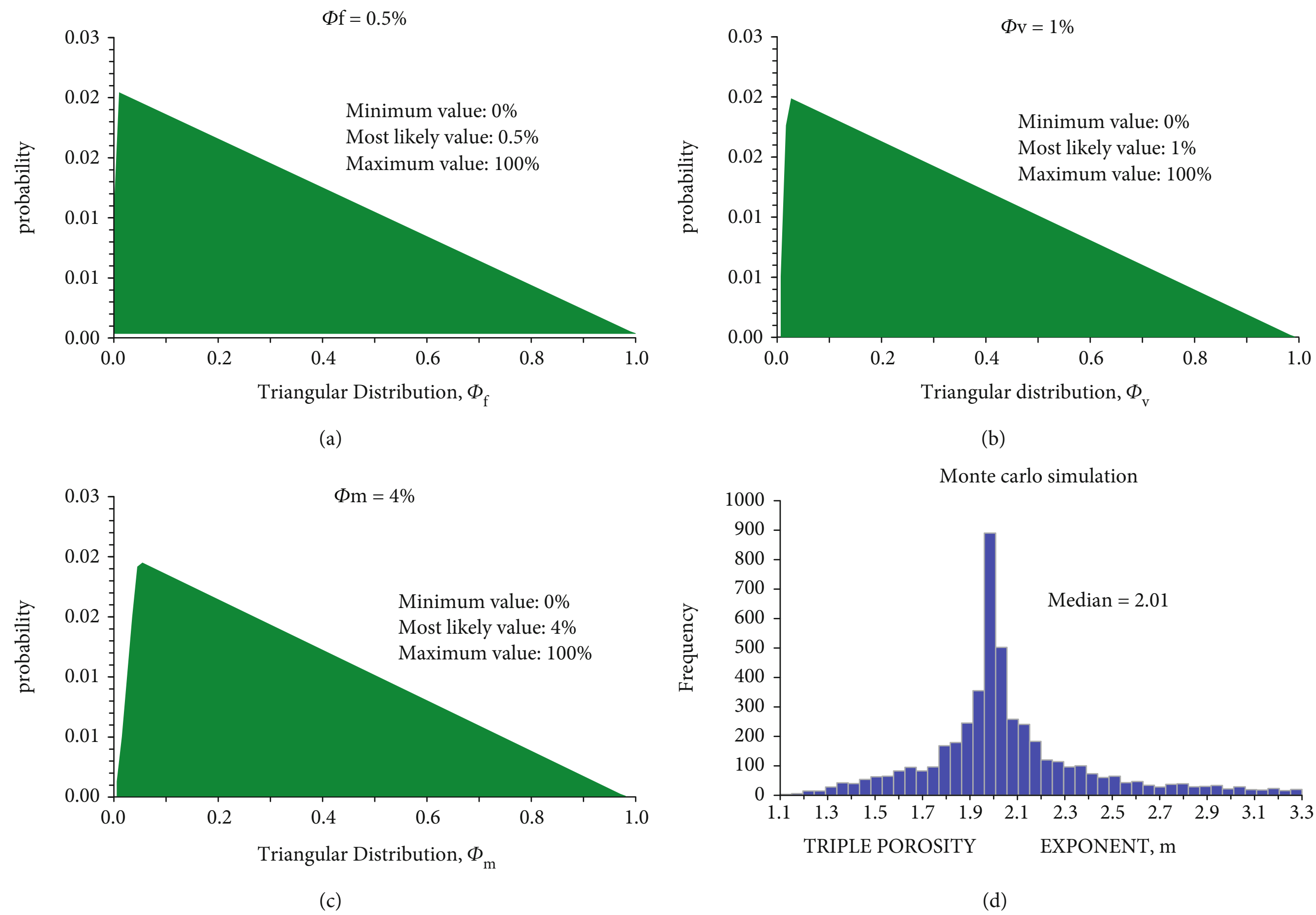

Figure 8: m value of low-porosity triple-pore medium reservoir (low-porosity carbonate rock) predicted by Monte Carlo simulation [20].

The calculation process is presented in the Appendix and Figure 5 shows the model-development process. Figure 6 shows the volume model of the triple-porosity value of a triple-porosity media reservoir.

A, B, and C are the schematic diagrams showing the physical models of each step. A represents the water-soaked intergranular pores, B the system with the matrix and vugs (the vugs are filled with water), and C the composite system (intergranular pores, vugs, and fractures). The total porosity and cementation exponent (Φ_{bv} and m_{bv}) of the dual-porosity system with the matrix and vugs in the triple-porosity composite system are calculated by m_v and Φ_v, using Equation (1) of the dual-porous system with the matrix and vugs. Φ_{bv} and m_{bv} are taken as matrix block porosity Φ_b and corresponding cementation exponent m_b in Equation (2) of the dual-porosity system with the matrix and fractures combining Φ_f.

The volume of the composite system is composed of the volumes of fractures, nonconnected vugs, matrix volume, and solid matrix. V_{ms} is the volume of the matrix block of the composite system, V_{v+ms} is the volume of the double-hole system with the matrix and vugs in the composite system, and V is the total volume of the composite system.

3. Results and Discussion

According to the triple-porosity model developed in the work (see Equation (3)), we obtained the relationship between the total porosity and cementation exponent m of the triple-porosity medium composite system with different combinations of fractures and nonconnected vug porosity (see Figure 7). The m value of the triple-porosity medium composite system (such as carbonate reservoir) varied from 1 to 3.6, mainly distributed in the range of 1.8 to 2.2 and converged at 2. The complex and long geological evolution process has led to serious heterogeneity of the triple-porosity media reservoir, making the irregular combination of matrix pores, fractures, and vugs in the reservoir and uncertain distribution characteristics. The decreased m value caused by fractures (or connected vugs) and the increased m value caused by nonconnected vugs offset each other, so the m value of the triple-porosity media reservoirs changed around 2.

The triple-porosity model developed in the work is more convergent than Al-Ghamdi et al.'s model [13], so the former is reliable. The rock petrophysics experiment data of carbonate rock were sampled by Ragland [17] in the Middle East. Most of the data points fell within the results calculated by substituting several hypothetical fracture-vug-

Table 1: m values of the triple-porosity media reservoir at various combinations of matrix porosity, fracture porosity, and nonconnected vug porosity.

Assumptions			Results	Sensitivity		
Φ_f (v/v)	Φ_v (v/v)	Φ_m (v/v)	m	Φ_f	Φ_v	Φ_m
0.005	0.005	0.05	2.00	-16.6%	79.7%	-3.7%
0.005	0.01	0.05	2.01	-16.3%	79.4%	-4.3%
0.005	0.025	0.05	2.01	-15.9%	78.8%	-5.3%
0.005	0.05	0.05	2.02	-16.5%	75.0%	-8.5%
0.005	0.075	0.05	2.03	-17.1%	75.6%	-7.3%
0.005	0.1	0.05	2.04	-16.5%	71.1%	-12.4%
0.005	0.15	0.05	2.07	-12.7%	67.5%	-19.8%
0.005	0.2	0.05	2.08	-13.2%	61.4%	-25.4%
0.005	0.05	0.05	2.02	-15.2%	76.3%	-8.6%
0.01	0.05	0.05	2.02	-15.9%	77.2%	-7.0%
0.025	0.05	0.05	2.02	-13.7%	79.7%	-6.6%
0.05	0.05	0.05	2.01	-13.1%	81.4%	-5.4%
0.075	0.05	0.05	2.01	-12.4%	81.2%	-6.4%
0.1	0.05	0.05	2.01	-10.2%	84.1%	-5.7%
0.15	0.05	0.05	2.00	-9.4%	85.8%	-4.8%
0.2	0.05	0.05	2.00	-8.1%	87.4%	-4.5%
0.005	0.01	0.005	2.02	-13.3%	82.2%	-4.5%
0.005	0.01	0.01	2.01	-14.6%	80.4%	-5.0%
0.005	0.01	0.025	2.01	-16.0%	79.9%	-4.1%
0.005	0.01	0.05	2.01	-15.6%	80.8%	-3.6%
0.005	0.01	0.075	2.01	-18.4%	77.5%	-4.2%
0.005	0.01	0.1	2.01	-20.1%	75.7%	-4.2%
0.005	0.01	0.15	2.01	-20.9%	75.1%	-4.1%
0.005	0.01	0.2	2.00	-20.1%	75.3%	-4.6%

type combinations into Equation (3) (see Figure 7). It also corroborated the accuracy of the triple-porosity model developed in the work. In the upper left corner of Figure 7, there are a small number of rock-electricity experimental data points that do not fall within the results calculated by substituting several hypothetical fracture-vug-type combinations into Equation (3). These rock samples have many fractures and few or even no holes, which do not belong to the combination of several fracture-vug-type ratios assumed in Figure 7. Three-porosity media reservoirs also have dual-porosity media reservoirs of the local matrix-porosity fracture type and matrix-porosity vug type, and the heterogeneity and anisotropy of triple-porosity media reservoirs are very common. The changes in time and space scales of many influencing factors such as structure, sedimentation, and diagenesis have led to limitations in man-made assumptions due to the evolution of the earth's complex systems.

Wang and Peng [20] used the Monte Carlo method to simulate the random distribution of fractures and vugs in carbonate reservoirs. The method was used as a supplement to the model in the work to make the predicted results more accurate. For the triple-porosity reservoir with unknown severe heterogeneity, the porosity of different reservoir spaces in the reservoir is first incorporated into Equation (3) for cementation index m. Then, the m value of the triple-porosity media reservoir can be predicted by simulation. As an example, Monte Carlo simulation [20] predicts that the m value of the triple-porosity media reservoir with $\Phi_f = 0.5\%$, $\Phi_v = 1\%$, and $\Phi_m = 4\%$ (low-porosity carbonate rock) is equal to 2.01, using the triple-porosity model developed in the work for 10,000 experiments (see Figure 8). Since the dual-porosity medium reservoir is a particular case of the triple-porosity one, this method can be used to obtain the m value.

Table 1 lists the m value of the triple-porosity media reservoir by Monte Carlo simulation based on the new triple-porosity models (see Equation (3)), setting the different ratios of matrix porosity, fracture porosity, and nonconnected vug porosity. The results show that the m value of the triple-porosity media reservoir converges at 2, and fractures decreased the m value but with increased vugs. The sensitivity of nonconnected vug porosity is more significant than that of fracture porosity and matrix porosity.

4. Conclusions

The conductivity of the triple-porosity media reservoir was the external macroscopic expression of the microscopic conductive network. In the triple-porosity media reservoirs with severe heterogeneity, such as carbonate rock, the carefully selected small-scale core plugs without vugs and/or microfractures could not represent the large-scale rock detected by the resistivity meter. Parameter m obtained by the laboratory analysis of the core plug should be used with caution.

In the triple-porosity medium reservoir, fractures decreased the m value, but vugs increased. The mixing of intergranular pores, vugs, and fractures made the m value of the triple-porosity media reservoir vary around 2.

The work proposed a new model for calculating the cementation exponent of the triple-porosity medium reservoir. It could predict the m value of an unknown triple-porosity medium reservoir with severe heterogeneity.

Appendix

The vug porosity of the dual-porosity system with the matrix and vugs in the triple-porosity composite system is expressed as

$$\phi_v' = \frac{\phi_v}{1-\phi_f}. \quad \text{(A.1)}$$

The total porosity of the dual-porosity system with the matrix and vugs in the triple-porosity composite system is expressed as

$$\phi_{bv} = \phi_v' + \phi_b\left(1-\phi_v'\right). \quad \text{(A.2)}$$

After simplifying,

$$\phi_{bv} = \frac{\phi_v + \phi_m}{1-\phi_f} = \frac{\phi_v + \phi_b(1-\phi_v-\phi_f)}{1-\phi_f}. \quad \text{(A.3)}$$

An equation for calculating the m value of the dual-porosity system with the matrix and vugs [6] is denoted as

$$m = \frac{\lg\left\{\phi_b^{mb}\left[\left(1+2\phi_v-2\phi_b^{mb}(\phi_v-1)\right)/\left(\phi_b^{mb}(2+\phi_v)+1-\phi_v\right)\right]\right\}}{\lg\phi}. \quad \text{(A.4)}$$

After substituting Φ_v and Φ_{bv} into Equation (A.4), we obtain

$$m_{bv} = \frac{\lg\left\{\phi_b^{mb}\left(\left(1-\phi_f+2\phi_v+2\phi_b^{mb}(1-\phi_v-\phi_f)\right)/\left(1-\phi_f-\phi_v+\phi_b^{mb}(2-2\phi_f+\phi_v)\right)\right)\right\}}{\lg\left\{(\phi_v+\phi_b(1-\phi_v-\phi_f))/(1-\phi_f)\right\}}. \quad \text{(A.5)}$$

An equation for calculating the m value of the dual-porosity system with the matrix and fractures [8] is expressed as

$$m = \frac{\lg\left[\phi_f + \phi_b^{mb}(1-\phi_f)\right]}{\lg\phi}. \quad \text{(A.6)}$$

Cementation exponent m of the triple-porosity composite system is calculated by substituting total porosity Φ_{bv} (see Equation (A.3)) and corresponding cementation index m_{bv} (see Equation (A.5)) of the dual-porosity system with matrix and vugs as the Φ_b and m_b of the dual-porosity system with matrix and fractures into Equation (A.6). Then, Equation (A.7), i.e., Equation (3) in the main text, is obtained.

$$m = \frac{\lg\left\{\phi_f + (1-\phi_f)\left[(\phi_v+\phi_b(1-\phi_v-\phi_f))/(1-\phi_f)\right]^{\lg\left\{\phi_b^{mb}\left(\left(1+2\phi_v-\phi_f+2\phi_b^{mb}(1-\phi_v-\phi_f)\right)/\left(\phi_b^{mb}(2-2\phi_f+\phi_v)+1-\phi_v-\phi_f\right)\right)\right\}/\lg\left\{(\phi_v+\phi_b(1-\phi_v-\phi_f))/(1-\phi_f)\right\}}\right\}}{\lg\phi}. \quad \text{(A.7)}$$

Nomenclature

- Φ: The total porosity of the composite system (the triple-porosity system with intergranular pores, fractures, and vugs)
- Φ_f: The porosity of natural fractures, attached to the overall volume of the composite system
- Φ_v: The porosity of nonconnected vugs, attached to the overall volume of the composite system
- Φ_m: The porosity of the matrix block attached to the overall volume of the composite system
- Φ_b: The porosity of the matrix block attached to the whole volume of the matrix system, equivalent to the porosity of a nonfracture core plug
- Φ_v': The proportion of the vug volume in the composite system to the remaining volume of the composite system without fractures (the dual-porosity system with the matrix and vugs in the composite system)

Φ_{bv}: The proportion of the volume of the vugs and the matrix pore volume in the composite system to the remaining volume of the composite system without fractures (the total porosity of the dual-porosity system with matrix and vugs in the composite system)
m: The porosity exponent (cementation exponent) of the composite system
m_b: The porosity exponent of the matrix block in the composite system (the porosity exponent of Φ_b)
m_{bv}: The porosity exponent of the dual-porosity system with the matrix and vugs in the composite system (the porosity exponent of Φ_{bv}).

Data Availability

The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare that there is no conflict of interest.

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