

Article

Study on Applicability of Ball-and-Stick Model in Reservoir Pore-Throat Network Simulation

Jinyou Dai ^{1,2,*}, Yangyang Shi ², Xizhen Lei ², Xiaofeng Zhou ^{1,2} , Zhiyang Pan ², Xiaoshu Shen ² and Sha Pi ²

¹ State Key Laboratory of Petroleum Resources and Prospecting, China University of Petroleum (Beijing), Beijing 102249, China; zhouxif@cup.edu.cn

² College of Petroleum Engineering, China University of Petroleum (Beijing), Beijing 102249, China; sy711829@163.com (Y.S.); lxz778802@163.com (X.L.); pzy2340690@163.com (Z.P.); aishishangreal@163.com (X.S.); pi20220222@163.com (S.P.)

* Correspondence: djy@cup.edu.cn; Tel.: +86-010-89733992

Abstract: At present, the ball-and-stick model is widely used to simulate the reservoir pore-throat network. However, due to the large span of reservoir pore-throats, there is still a lack of effective verification on whether the ball-stick model is fully applicable. The configuration analysis of a constant velocity mercury injection curve is carried out by using configuration theory and the hierarchical analysis method. The applicability of the ball-and-stick model in a reservoir pore-throat network simulation is discussed by interpreting the reservoir pore-throat structure information behind the configuration. The results show that there are two configuration regions, A and B, in the constant velocity mercury injection curve. In configuration region A, the mercury saturation of pores, the pore channel and the throats increase monotonically with the increase in mercury inlet pressure, indicating that pore channels and throats coexist in this configuration region, the pore-throat ratio is greater than one, and the ball-and-stick model is applicable. In the B configuration region, mercury saturation in pores and throats increases monotonically with the increase of mercury inlet pressure, while mercury saturation in the pore channel remains unchanged, indicating that this configuration region is basically throat with a porethroat ratio of one. The ball-and-stick model is no longer applicable, and the capillary model is more suitable. The ball-and-stick model combined with the capillary model can simulate the full-scale pore throat network of the reservoir. This study provides a method to calibrate the application zone of ball-stick model and capillary model by using constant velocity mercury injection curve configuration, which has important guiding significance for the simulation of the reservoir pore-throat network and the study of the seepage law.

Keywords: reservoir pore-throat network; simulation; ball-and-stick model; applicability; constant velocity mercury injection; configuration analysis



Academic Editor: Udo Fritsching

Received: 21 December 2024

Revised: 20 January 2025

Accepted: 23 January 2025

Published: 6 February 2025

Citation: Dai, J.; Shi, Y.; Lei, X.; Zhou, X.; Pan, Z.; Shen, X.; Pi, S. Study on Applicability of Ball-and-Stick Model in Reservoir Pore-Throat Network Simulation. *Processes* **2025**, *13*, 433. <https://doi.org/10.3390/pr13020433>

Copyright: © 2025 by the authors. Licensee MDPI, Basel, Switzerland. This article is an open access article distributed under the terms and conditions of the Creative Commons Attribution (CC BY) license (<https://creativecommons.org/licenses/by/4.0/>).

1. Introduction

A pore is a space in a rock that is not filled by solid material, which is composed of two parts: a pore channel and a throat [1]. Among them, the opening degree of the pore channel determines the reservoir fluid capacity. The throat is a narrow channel connecting the pore channel with a relatively small opening, which controls the permeability of the reservoir fluid [2]. Reservoir pore channels and throats are coupled to form a complex spatial topological network of pore-throats. In recent years, thanks to advances in scanning imaging and digital core technology, the ball-and-stick model (which uses spheres and cylinders to represent large pore channels and slender throats, respectively) has been

widely used to simulate the reservoir pore-throat network and study its seepage law [3–7]. Wu Xiang et al. (2024) elaborated on the ball-and-stick model to simulate a reservoir pore-throat network based on core scanning imaging and three-dimensional image reconstruction [3]. Li Junjian et al. (2018) [4] selected four cores of the Donghe sandstone reservoir in the Tarim Basin with different pore structure types to carry out water-driven oil scanning imaging experiments. The ball-and-stick model was used to extract pore-throat network parameters and analyze the distribution of the pore-throat radius, shape factor, coordination number, and connectivity, so as to study the influence of the microscopic pore-throat structure heterogeneity on the distribution form of the remaining oil. Zhao Wen et al. (2022) [5] used a ball-and-stick pore-throat network model to carry out numerical simulation research on tight sandstone gas charging, discussed the charging mechanism of tight sandstone gas on micro-scale, and analyzed the gas-water occurrence characteristics during the charging process. Wu Jianbiao et al. (2023) [6] took the tight sandstone gas reservoir of the Lower Shihezi Formation in the J area of the Ordos Basin as the research object, used Avizo software to process multi-scale 3D CT images, and built the 3D pore-throat ball and stick network model. In addition, they calculated the throat radius, pore radius, coordination number, throat length, throat shape factor, pore shape factor, and other parameters. Chen Mingyang et al. (2024) [7], constructed a three-dimensional pore network model of the Neogene Guantao Formation reservoir in Penglai 19-3 oilfield, Bohai Sea, by using the maximum-sphere method and carried out a numerical simulation based on an understanding of physical properties, pore types, and CT scanning technology for digital core analysis. Subsequently, the differences in seepage flow in different displacement directions of the core were analyzed. In summary, the application of the ball-and-stick model has significantly promoted the simulation of the reservoir pore-throat network and the study of the seepage law.

The pore size of a reservoir varies. Based on the pore diameter, Zou Caineng et al. (2011) [8] classified the pores of oil and gas reservoirs into three types: millimeter pores (>1 mm), micron pores ($1\text{--}1000\text{ }\mu\text{m}$) and nano-pores ($<1\text{ }\mu\text{m}$). Using field emission sweep electronic microscopy to observe the pore size, it was found that the pore diameter of conventional reservoirs was generally greater than $1\text{ }\mu\text{m}$. The nanoscale pore diameter in a tight sandstone oil and gas reservoir ranges from 10 to 1000 nm, and the main body ranges from 300 to 900 nm. The nanoscale pore diameter of a shale gas reservoir ranges from 5 to 300 nm, and the main body ranges from 80 to 200 nm. Zhu Rukai et al. (2016) [9] proposed a “pore quarter method” evaluation scheme based on the rock pore structure anatomy and further subdivided the pores into millimeter pores (>1 mm), micron pores ($1\text{--}1000\text{ }\mu\text{m}$), submicron pores ($100\text{--}1000\text{ nm}$) and nano-pores ($<100\text{ nm}$). With reference to the classification scheme mentioned above, in this paper, millimeter, micron and submicron pores with a pore size over 300 nm are collectively referred to as large pores (or large pore throats), and submicron pores (with a pore size lower than 300 nm) and nano-pores are collectively referred to as small pores (or small pore throats). According to this standard (the 300 nm limit here is only a reference value), the ball-and-stick pore throat network model established by scholars and the statistical data of the pore throat radius are re-examined [4–7], and it was found that the pore throat scale simulated by the reservoir pore throat network is mainly large pores, and rarely reaches the small pore size. In the actual reservoir, the pore throat spans a wide range [10], and large pores and small pores coexist, but it is difficult to simulate small pores with the ball-and-stick pore-throat network model. This raises the question, “Is the single ball-and-stick model suitable for simulating the full-scale pore-throat network of a reservoir?”—Clarifying this problem has important theoretical and practical significance for objectively simulating reservoir pore-throat networks and accurately studying—seepage laws.

As a hidden topological property, configuration is defined as a specific way in which a group of Spaces are interconnected to form networks. Configuration focuses on the relationship of each part and the relationship between the part and the whole, aiming to reveal the complex structure and its formation mechanism [11]. Configuration was originally an architectural term [12,13], and later it was widely used in many fields such as biology, machinery, materials, history, humanity, and petroleum to characterize the hierarchical relationship between local and overall structures [14–16]. In 1977, Allen introduced configuration into the study of river sedimentation for the first time at the first International Symposium on fluvial sedimentology to characterize the hierarchical structure of geologic bodies [17]. Since then, many scholars have carried out a lot of studies on sedimentary configuration, sequence configuration, reservoir configuration, etc., which has effectively guided oilfield development and residual oil exploitation potential [18–21]. Constant velocity mercury injection is an important method for measuring capillary pressure curves of rocks using mercury as a displacement fluid. Besides the capillary pressure curves of total pore throat (or pore), capillary pressure curves of pore channels and throats can also be measured separately. The three curves of constant velocity mercury injection (pores, pore channels and throats) are not only closely related, but also have obvious differences in morphology, so that the combined curves of the three show topological properties and hierarchical structures, which can better characterize the differences in reservoir pore structure [22]. Therefore, the configuration theory and hierarchical analysis method are used to divide the configuration of constant velocity mercury injection curve in this paper. The applicability of ball-and-stick model in reservoir pore-throat network simulation is discussed by interpreting the pore throat structure information behind the curve configuration, capturing the difference between large pores and small pores in pore throat structure and fluid flow behavior. This study will make us realize that the ball-and-stick model is suitable for the simulation of large pores, especially in the treatment of large pores and high permeability reservoirs, because the pore channels and throat of big pores are relatively independent, the pore and throat ratio is greater than one, and the flow capacity is strong in big pores. However, there is no difference in size between pore channels and throats of small pores, pore and throat ratio is equal to one and it is like a bundle type, and the flow ability of fluid in small pores is weak. Therefore, capillary model is more suitable for small pore simulation, especially in dealing with small pore and low permeability reservoir. In the simulation of reservoir pore-throat network, the combination of ball-and-stick model and capillary model and the collaborative simulation according to the composition ratio will help to establish a more objective and perfect full-scale pore-throat network model.

2. Methods

2.1. Characteristics of Constant Velocity Mercury Injection Curve

Y oilfield is located in the southwest of Yishan Slope of Ordos Basin, located in Qingyang City of Gansu Province (Figure 1), which covers an area of 5000 km². The main producing layer of the oil field belongs to the Triassic Yanchang chang 8 oil group, which is a delta front deposit. The average porosity of reservoir is 12.1% and the average permeability is $1.19 \times 10^{-3} \mu\text{m}^2$, which belongs to a low porosity and low permeability reservoir [23]. Core observation and sampling were carried out in the core taking well of Chang 8 reservoir in Y oilfield, and the obtained core samples were tested for physical properties. According to the difference of reservoir quality (good, medium and poor), three typical reservoir samples with porosity between 10~15% and permeability between $0.3 \times 10^{-3} \mu\text{m}^2$ and $1.3 \times 10^{-3} \mu\text{m}^2$ were selected for constant velocity mercury injection experiment.

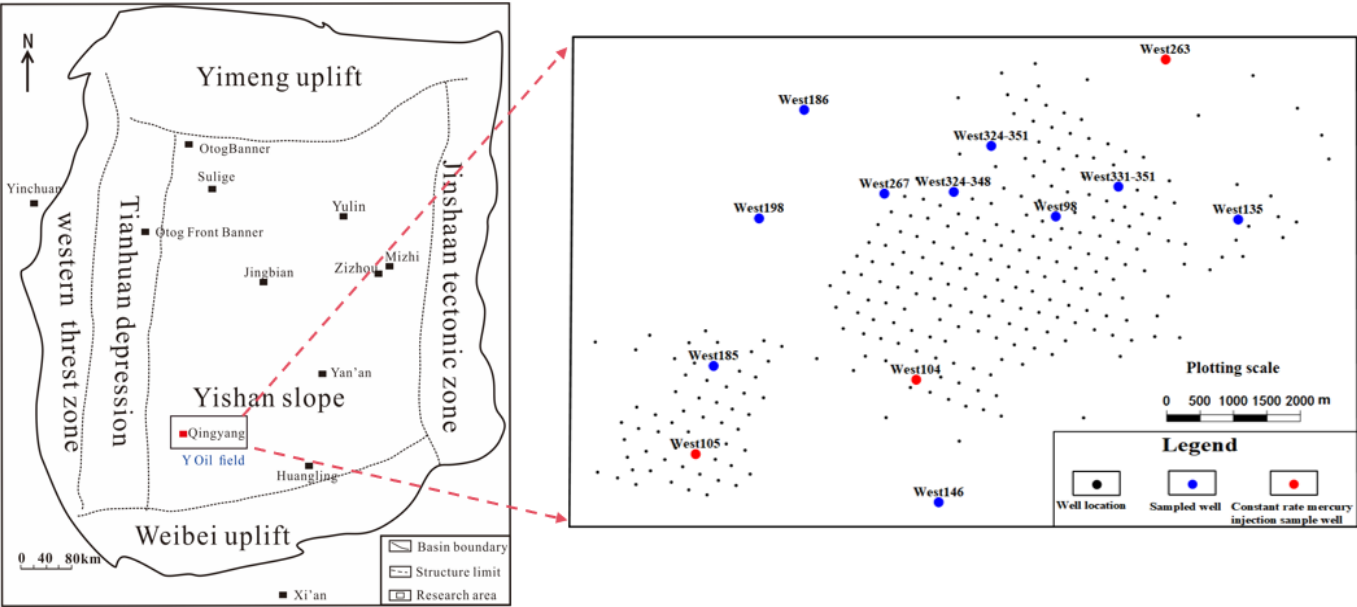


Figure 1. Y Oil field location map.

The experiment of constant velocity mercury injection was completed by reservoir Seepage Laboratory of Langfang Branch, Research Institute of Petroleum Exploration and Development, China. In the experiment, ASPE-730 constant velocity mercury injection instrument was used to inject mercury at a quasi-static speed of 5×10^{-5} mL/min, and the mercury inlet pressure and saturation were recorded by a high-precision pressure sensor. The experiment ended when the highest mercury inlet pressure reached 6.2 MPa. Table 1 shows the experimental results data, and Figure 2 shows the measured constant velocity mercury injection curve.

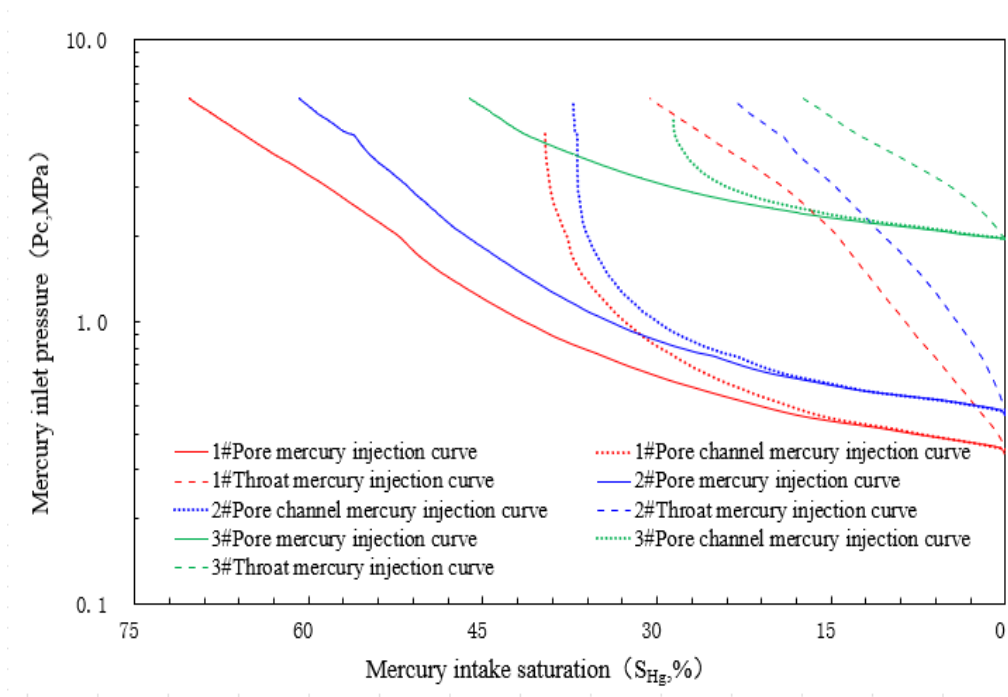


Figure 2. Constant velocity mercury injection curves.

Table 1. Results data table of constant velocity mercury injection experiment.

Rock Core Number	Well Number	Well Depth (m)	Porosity/%	Permeability/ $10^{-3} \mu\text{m}^2$	Average Throat Radius/ μm	Average Pore Radius/ μm	Average Pore-Throat Radius Ratio	Maximum Pore Mercury Saturation/%	Maximum Pore Channel Mercury Saturation/%	Maximum Throat Mercury Saturation/%
1#	West 104	2161.1	14.20	1.220	1.25	125.90	153.30	70.29	39.63	30.66
2#	West 105	2156.0	12.27	0.828	0.98	128.40	180.63	60.78	37.20	23.58
3#	West 263	2136.6	9.77	0.331	0.29	140.68	534.66	46.11	28.66	17.44
Average value			12.08	0.793	0.84	131.66	289.53	59.06	23.89	35.16

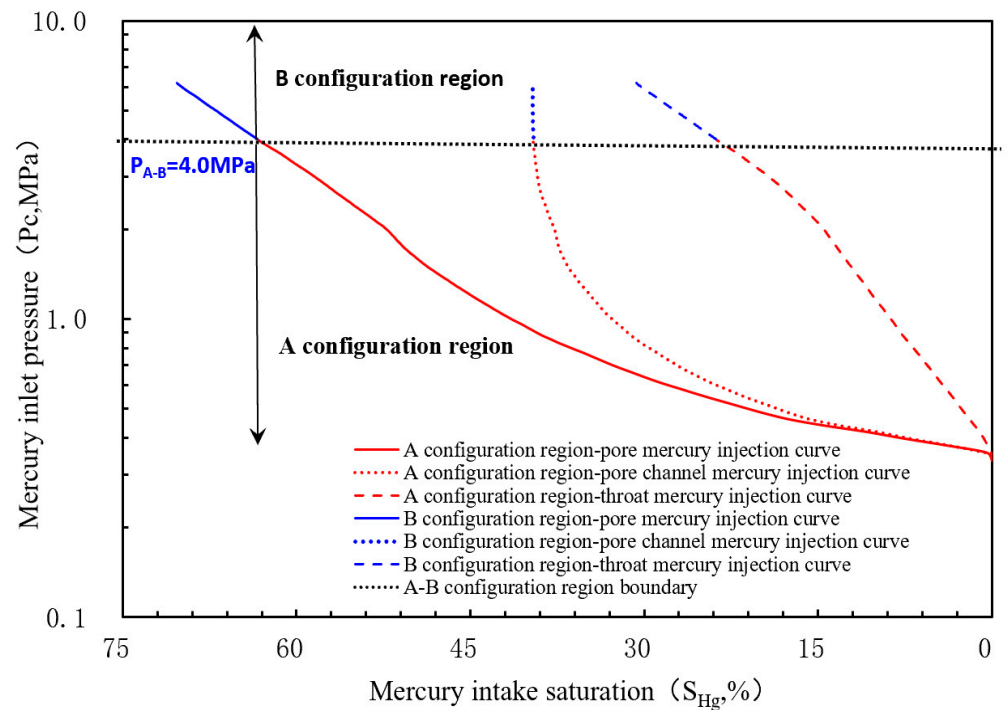
It can be seen from Table 1: from 1#→2#→3#, the reservoir physical properties gradually deteriorate, and they represent good, medium and poor, three reservoir types of Chang 8. The average porosity of the three samples is 12.08%, the average permeability is $0.793 \times 10 \times 10^{-3} \mu\text{m}^2$, the average throat radius is 0.84 μm , the average pore radius is 131.66 μm , the average pore throat radius ratio is 289.53, the average maximum pore mercury saturation is 59.06%, and the average maximum pore channel mercury saturation is 23.89%. The average maximum throat mercury saturation was 35.16%.

As can be seen from Figure 2: from 1#→2#→3#, with the deterioration of reservoir quality, the maximum mercury saturation of pores, pore channels and throats decrease successively, and the drainage pressure increases successively, and the curve shifts to the upper right as a whole. In the experimental pressure range (0 to 6.2 MPa), constant velocity mercury injection curves are characterized as “mercury injection saturation in pores and throats increases with the increase of mercury injection pressure, while mercury injection saturation in pores channel increases first and then remains unchanged”. Scholars [24–26] have tested 38 samples from more extensive areas (Longdong, Jiyuan, Xifeng, Nanliang-Huachi) and horizons (Chang 6, Chang 7 and Chang 8 oil groups) in the Ordos Basin, showing that the variation characteristics of constant velocity mercury injection curve are universal and do not change according to different regions or horizons.

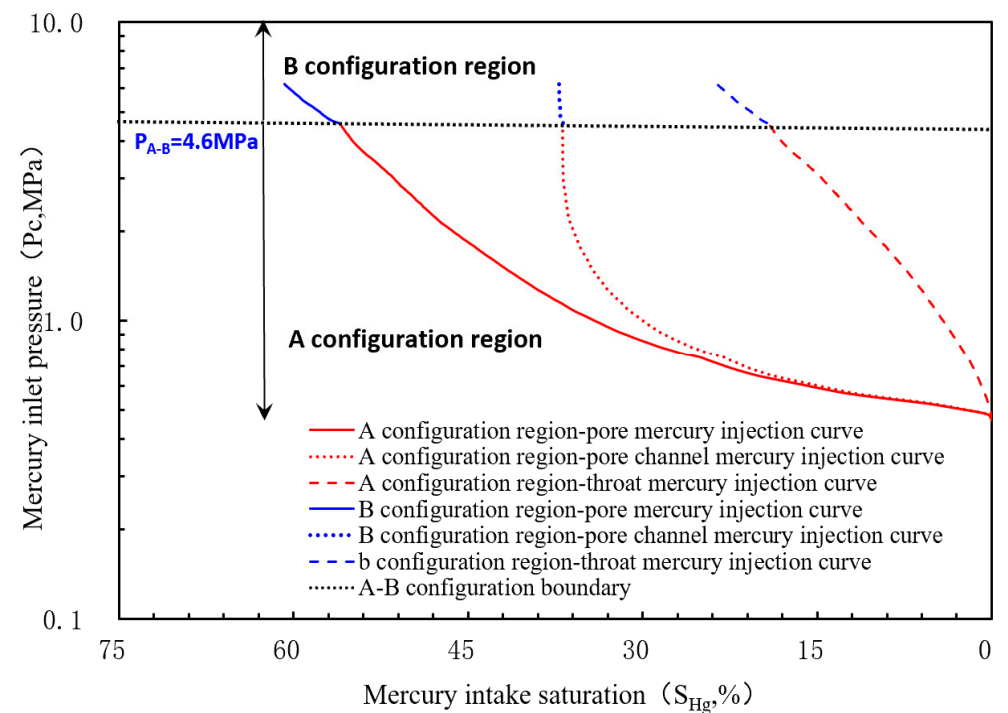
2.2. Constant Velocity Mercury Injection Curve Configuration

Constant velocity mercury injection curve covers the comprehensive information of pores, pore channels and throats, which can better characterize the pore throat structure of the reservoir. According to the characteristics and morphological differences of constant velocity mercury injection combination curves (pore, pore channels and throat mercury injection curves), the configuration of constant velocity mercury injection curve was divided into two interrelated configuration regions with the mercury injection pressure at the initial constant point of mercury saturation in the pore channel as the boundary (Figure 3).

In the A configuration region, the mercury inlet pressure is relatively low and the pore throat is relatively large. In this configuration region, mercury saturation in pores, pore channels and throats increase monotonically with the increase of mercury inlet pressure, which reflects the relative independence of pore channels and throats. In the B configuration region, the mercury inlet pressure is relatively high and the pore throat is relatively small. In this configuration region, mercury saturation in pores and throats increases monotonically with the increase of mercury inlet pressure, while mercury saturation in pore channels remains unchanged, reflecting the characteristics of throat predominant and undeveloped pores. The three samples have similar configuration characteristics, but there are some differences in mercury inlet pressure (P_{A-B}) limits between configuration regions. As the reservoir quality deteriorates (from 1# to 2# to 3# samples), the mercury inlet pressure limit gradually increases (from 4.0 MPa to 4.6 MPa to 5.2 MPa).

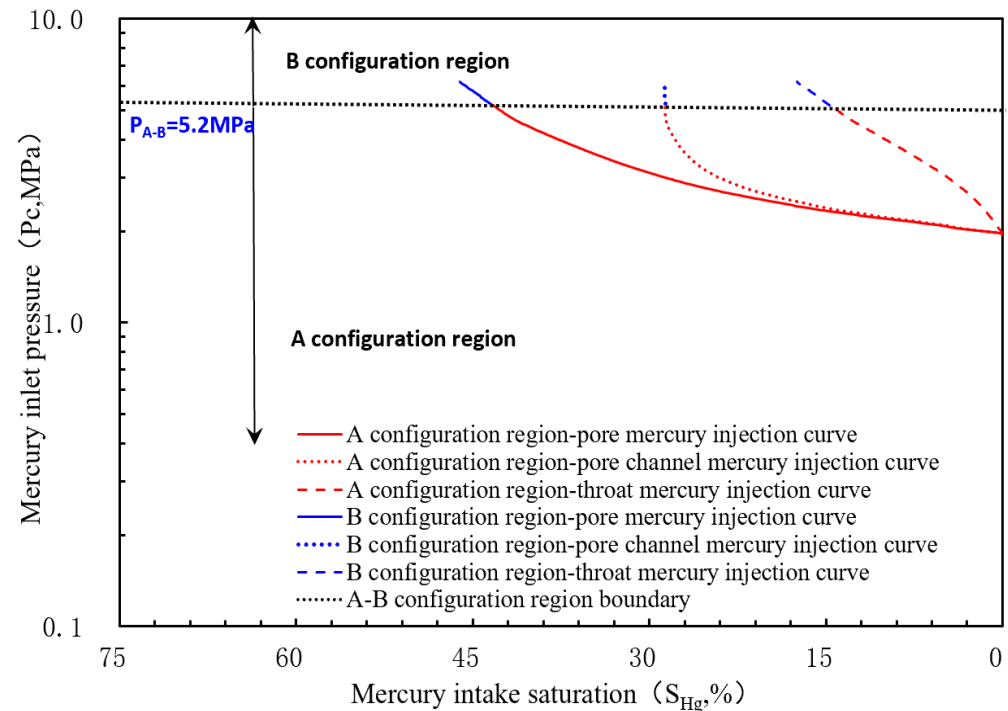


(a) 1# sample constant velocity mercury injection curve configuration



(b) 2# sample constant velocity mercury injection curve configuration

Figure 3. Cont.



(c) 3# sample constant velocity mercury injection curve configuration

Figure 3. Constant velocity mercury injection curve configuration diagram.

The configuration of constant velocity mercury injection curve is the specific response to the difference of pore throat structure inside the reservoir pores, and can better reveal the pore throat hierarchy inside the reservoir pores. Therefore, the pore throat structure information behind the constant velocity mercury injection curve was further analyzed to reveal the pore throat structure difference.

2.3. Differences in Pore Throat Structure Behind the Configuration

Considering that in the process of mercury injection, if the pores comply with Washburn equation [27], then:

$$P_c = \frac{2\sigma \cos \theta}{r} \quad (1)$$

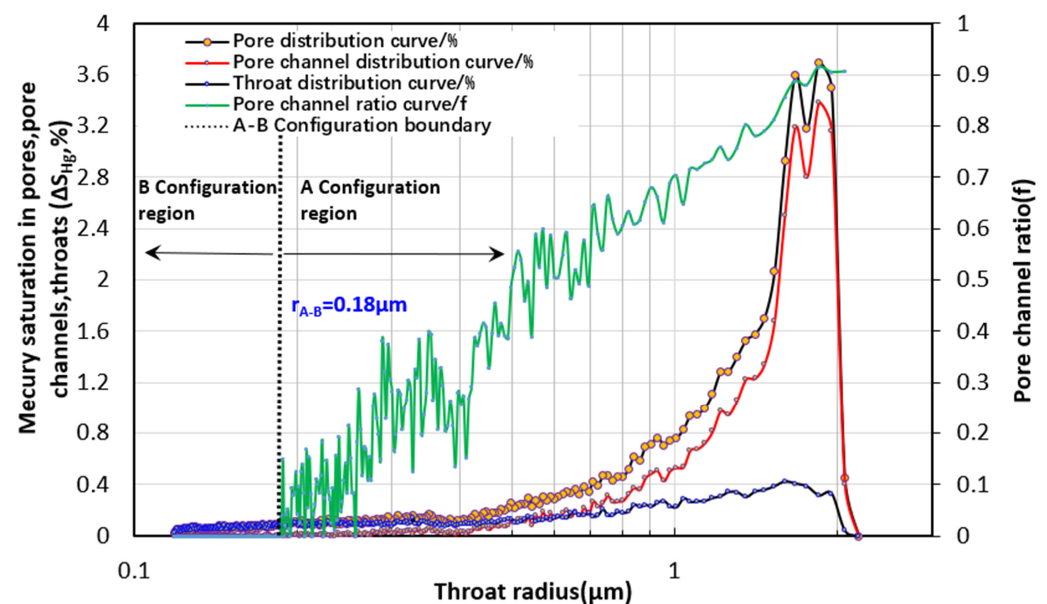
In the formula: P_c -Capillary pressure, MPa; σ -Mercury and air interfacial tension, N/m; θ -Contact Angle, rad; r -Throat radius, μm .

Since the interfacial tension of mercury-vacuum is 0.48 N/m and the contact Angle is 140° (2.44346 rad), Formula (1) can be rewritten as:

$$r = \frac{0.7354}{P_c} \quad (2)$$

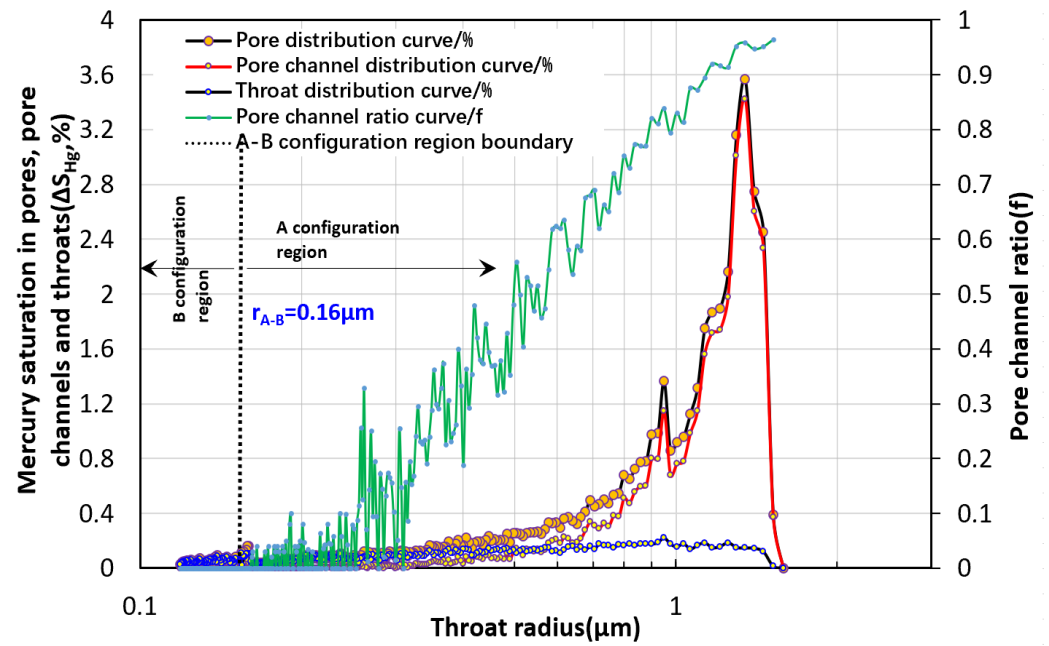
Firstly, Washburn equation is used to convert mercury inlet pressure into throat radius according to Equation (2). Then, combined with the mercury saturation data of adjacent mercury inlet pressure test points, the mercury inlet saturation of the test interval is calculated. Finally, using the throat radius and its corresponding interval mercury inlet saturation, a new distribution curve of reservoir pores, pore channels and throats was compiled (Figure 4). It can be seen from Figure 4 that the distribution curves of pores, pore channels and throats of the three samples have similar characteristics, and their variation rules are basically the same.

- (1) The three distribution curves are all positive skew, and the pore distribution curve is the envelope line, and the distribution curves of the pore channels and throats are complementary. With the deterioration of reservoir quality (from sample 1#→2#→3#), the throat radius limit r_{A-B} between configuration regions A and B gradually decreases ($0.18\ \mu\text{m} \rightarrow 0.16\ \mu\text{m} \rightarrow 0.14\ \mu\text{m}$).
- (2) A configuration region: the throat radius is bigger than r_{A-B} . According to the definition of macropore and micropore in this paper, the pores in the A configuration region basically belong to the category of macropore. At the initial stage of mercury injection, the mercury saturation in the pore channel area was much higher than that in the throat, and the pore channel ratio (the proportion of pore channel to pore) was about 0.9; then, with the increase of mercury inlet pressure, mercury saturation in the pore channel area decreased rapidly, and mercury saturation in the throat area decreased slowly, and the proportion of pore channel area decreased linearly until it reached 0. Because the decreasing rate of mercury saturation in the pore channels is greater than that in the throat area, the distribution curve of the pore channel and throat presents a unique X-shaped cross shape, and they are offset from each other. Although the pore channels to throat ratio is constantly changing during mercury intake, the A configuration region always shows the coexistence of pore channel and throat, and pore-throat ratio > 1 .
- (3) B configuration region: the throat radius is less than r_{A-B} . According to the definition of macropore and micropore in this paper, the pores in the B configuration region basically belong to the category of micropore. With the increase of mercury inlet pressure, the mercury saturation in the pore and throat region is equal, and the mercury saturation in the pore channel region (the proportion of the pore channel) are basically 0%. This shows that the B configuration region is basically throat (or pores, pore channel and throat is no difference), and pore-throat ratio is approximately one.

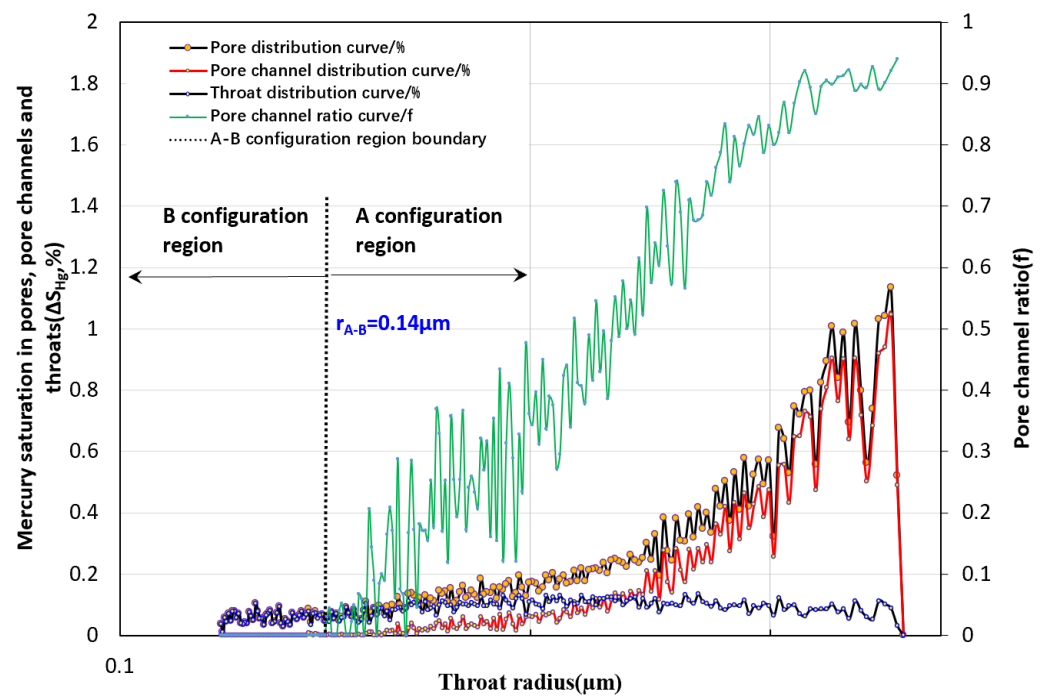


(a) 1# sample pore, pore channel and throat distribution curve

Figure 4. Cont.



(b) 2# sample pore, pore channel and throat distribution curve



(c) 3# sample pore, pore channel and throat distribution curve

Figure 4. Reservoir pore, pore channel and throat distribution curves.

3. Results

Reservoir are rock layer that stores and percolates fluids. The basic characteristics of reservoir are porosity and permeability. Reservoir porosity determines reservoir permeability, so the study of reservoir porosity is the basis of the study of reservoir permeability [28]. The study of reservoir porosity is usually based on the classification of pore throat. When the research purpose is different, the classification scheme is also different [29,30]. According to the appearance and scale of pore throat, the reservoir pores can be divided into four categories: interparticle pores, intergranular pores, interstitial pores and fractures, and the

reservoir throat can be divided into five categories, including crack type, pore shrinkage type, neck type, sheet type and bundle tube type [29]. According to the study [30], different throat types correspond to different pore-throat combination styles. Among them, the crack type, pore shrinkage type throat corresponds to the combination of large pore-thick throat, the neck type throat corresponds to the combination of large pore-fine throat, the sheet type throat corresponds to the combination of small pore-fine throat, and the bundle tube throat corresponds to the combination of micropore- microthroat. The pores in the micropore-microthroat combination are basically interstitial pores, while the pores in other pore-throat combinations include intergranular pores, intra-granular pores and cracks.

According to pore channel proportion, pore type, throat type, pore-throat combination pattern, throat radius, and seepage capacity, the reservoir pore throat structure model (Figure 5) was established. The differences in pore throat structure and fluid flow behavior between large pores in A configuration region and small pores in B configuration region are analyzed, and the applicability of ball-and-stick model in reservoir pore throat network simulation is confirmed.

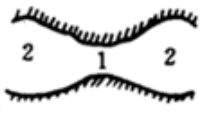
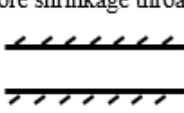
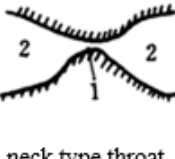
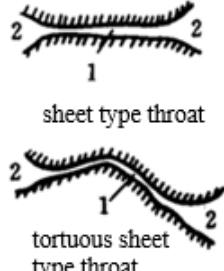
Configurational region	A		B
Pore channel ratio/f	>0		0
Pore type	Intergranular pores, intragranular pores, cracks		Interstitial pores
Throat type	crack type、pore shrinkage type、neck type、sheet type		bundle tube type
Pore-throat combination(1-Throat, 2-Pore)	 pore shrinkage throat  crack type throat Big pore- big throat combination	 neck type throat Big pore- fine throat combination	 sheet type throat tortuous sheet type throat Small pore- fine throat combination  bundle tube type throat Micropore- microthroat combination
Pore-throat ratio	>1		1
Throat radius	Big $\longrightarrow$ Small		
Seepage capacity	Strong $\longrightarrow$ Weak		
Pore throat network simulation model	 Ball-and-stick model		 Capillary model

Figure 5. Reservoir pore throat structure model.

As can be seen from Figure 5:

- (1) A configuration region: the pore channel ratio > 0; the pores are mainly intergranular pores, intragranular pores and cracks; the throat is mainly crack type, pore shrinkage type, neck narrow type and sheet type; with the decrease of throat radius, the reservoir pore-throat combination evolves from large pore-thick throat $\rightarrow$ large pore-thin throat $\rightarrow$ small pore-thin throat combination. The pores in this configuration region are mainly distributed between or inside the detrital particles, with large volume but small

number. The larger throat radius makes them show small capillary force seepage resistance, and the fluid has strong seepage capacity in them. Because the pore channels and throat are relatively independent and the pore-throat ratio is >1 , the ball-and-stick model is suitable.

- (2) B configuration region: the pore channel ratio is zero, the pores are mainly interstitial pores, the throats are bundle shaped, and the combination of pores and throats is micropores-microthroats. The pores in this configuration region are mainly inside the interstitial, with small volume and large number. The small throat radius makes them exhibit large capillary force seepage resistance. In addition, the flow path of the fluid is more tortuous, and the flow capacity of the fluid in it is weak. Since the pores in the B configuration region are bundle shaped and the pore-throat ratio is approximately one, indicating that there is no significant difference in the size of pores, pore channels and throats, the ball-and-stick model is no longer applicable, while the capillary model is more suitable.
- (3) The large pores in the A configuration region constitute the backbone of the reservoir pore throat network, and the small pores in the B configuration area are connected to the periphery of the large pore framework in capillary manner. The organic combination of large pores and small pores constitutes the full-scale spatial pore throat network of the reservoir. The ball-and-stick model is suitable for large pore throat simulation, especially when dealing with large pore and high permeability reservoir. The capillary model is more suitable for the simulation of bundle tube throat, especially when dealing with small pores and low permeability reservoir. Therefore, a single ball-and-stick model cannot simulate the full-scale pore throat network of the reservoir.

4. Discussion

4.1. The Reasons for Failure of Reservoir Pore-Throat Network Simulated by Ball-and-Stick Model

At present, the ball-and-stick model is mainly used to simulate reservoir pore-throat network [3–7]. Although the ball-and-stick model can solve the simulation problem of large pores well, the effective simulation of small pores has not been realized, mainly for the following three reasons:

On the one hand, the ball-and-stick model oversimplifies the small pore proportions. As we all know, core scanning imaging, 3D image reconstruction and pore extraction and modeling are the three important links in constructing reservoir pore throat network model. Thanks to the development of scanning imaging technology, multi-scale core imaging with sub-nanometer to centimeter-level resolution can be realized at present [3]. However, due to the limitation of imaging technology, a single imaging method with fixed resolution cannot resolve the structure distribution across scales. This requires the fusion of rock image data with different field of view and different resolution to achieve 3D image reconstruction. However, in the process of 3D image reconstruction, it is interfered by many factors such as image fusion algorithm, computing efficiency and inconsistent resolution. In the actual process, the information loss of a large number of small pores with high resolution is often much higher than that of large pores.

On the other hand, it is difficult for the ball-and-stick model to capture the widely distributed and large number of small pores, and can not establish an effective connection between small pores and large pores when extracting pores in the three-dimensional reconstruction of images. At present, small pores in image 3D reconstruction are often treated as isolated and disconnected pores or even eliminated [4,6]. This approach not only makes the small pores seriously missing, but also leads to the oil and gas flow behavior and

production contribution in the pores, which can not be truly reflected in the subsequent seepage simulation of the pore throat network.

Thirdly, in the process of reservoir pore-throat network simulation, porosity is often used as the basis for the selection of feature units and the measurement of model reliability [3,4]. Because the ball-and-stick model oversimplifies the small pores, the proportion of small pores (or their porosity components) in the reservoir pore-throat network simulation is greatly reduced compared with the actual reservoir, on the contrary, the proportion of large pores (or their porosity components) is significantly increased compared with the actual reservoir. Therefore, in the ball-and-stick pore throat network model established under porosity constraints, the relative ratio of large pores to small pores is seriously different from that of the actual reservoir, which also means that the permeability of the model is higher than that of the actual reservoir, thus overestimating the permeability of the reservoir fluid.

4.2. The Significance of Capillary Model for the Simulation of Pore-Throat Network

The significance of capillary model for the simulation of pore throat network is analyzed from three aspects, such as the proportion, mobility and contribution to production of small pores in the reservoir.

(1) The proportion of small pores in the reservoir

The mercury inlet pressure limit and maximum mercury inlet saturation in different configuration regions of 3 samples were statistically analyzed, and the proportion of small pores in the reservoir was analyzed. As can be seen from Table 2: From sample 1# to 2# to 3#, with the deterioration of reservoir physical properties, mercury inlet saturation of small pores in B configuration region gradually increases (from 36.72% to 43.87% to 56.83%), that is, the proportion of small pores is increasing. This shows that the poorer the reservoir physical properties, the higher the small pores proportion, the higher the proportion of reservoir space suitable for capillary model simulation, and the more important the capillary model is for the simulation of pore throat network.

Table 2. Statistical table of mercury inlet pressure limit and maximum mercury inlet saturation in different configuration regions.

Sample	Porosity/%	Permeability/ 10 ^{−3} μm ²	Configurational Region	Mercury Inlet Pressure Limit/MPa	Maximum Mercury Intake Saturation/%		
					Pore	Pore Channels	Throat
1#	14.2	1.22	A	≤4	63.28	39.63	23.65
			B	>4	100.00	39.63	60.37
2#	12.27	0.828	A	≤4.6	56.13	37.20	18.93
			B	>4.6	100.00	37.20	62.80
3#	9.77	0.331	A	≤5.2	43.17	28.66	14.51
			B	>5.2	100.00	28.66	71.34

Note: The maximum mercury saturation in the pores of the B configuration zone is 100%.

(2) Mobility of small pores in the reservoir

In the process of oilfield development, the production pressure difference of oil Wells is usually about 1~3 MPa or even higher. If the production pressure difference of 2 MPa is measured, it is equivalent to about 30 MPa experimental mercury inlet pressure [31]. As can be seen from Table 2, this pressure is significantly higher than the lower limit of mercury inlet pressure in B configuration region (the lower limit of mercury inlet pressure sample 1#, sample 2#, sample 3# is 4 MPa, 4.6 MPa, 5.2 MPa respectively). This shows that a large part of the small pores in the reservoir are in the movable range.

(3) Contribution of small pores in reservoir to oil and gas production

The contribution of small pores to oil and gas production is analyzed based on the water flooding experiment data of Chang 8 oil group in Y oilfield and the recovery parameters.

For water drive reservoirs, recovery can be expressed as:

$$E_R = E_{VA} \times E_{Vh} \times E_D \times 100\% \quad (3)$$

In the formula: E_R -Reservoir recovery, %; E_{VA} -areal sweep efficiency,%; E_{Vh} -vertical sweep efficiency,%; E_D -Displacement efficiency, %.

For the core water displacement experiment, supposing $E_{VA} = 100\%$, $E_{Vh} = 100\%$, then:

$$E_R = E_D \quad (4)$$

Formula (4) shows that in the water displacement experiment, the recovery rate is equivalent to the displacement efficiency under the condition of complete core washing. Therefore, Formula (4) can be rewritten as:

$$E_R = \frac{S_{oi} - S_{or}}{S_{oi}} \times 100\% = \frac{1 - S_{wi} - S_{or}}{1 - S_{wi}} \times 100\% \quad (5)$$

In the formula: S_{oi} -Initial oil saturation, %; S_{or} -Residual oil saturation, %; S_{wi} -Irreducible water saturation, %.

The data of 4 groups of water flooding experiments in Y oilfield show (Table 3) that the average irreducible water saturation of the reservoir is 29.3%, the average residual oil saturation is 30.8%, and the average final displacement efficiency is 56.4%.

Table 3. Water displacement test data table.

Well Number	Layer	Porosity (%)	Air Per-meability ($\times 10^{-3} \mu\text{m}^2$)	Irreducible Water Sat-uration (%)	Residual Oil Satu-ration (%)	Water Cut = 95%		Water Cut = 98%		Terminal Phase	
						Displacement Efficiency (%)	Injection Multiple (PV)	Displacement Efficiency (%)	Injection Multiple (PV)	Displacement Efficiency (%)	Injection Multiple (PV)
West105	Chang 8	11.8	1.13	29.3	35.9	24.3	0.88	35.2	2.44	49.2	16.6
	Chang 8	11.5	0.72	32.5	32.5	30.6	1.27	40.9	2.49	51.8	22.4
West119	Chang 8	14.8	1.56	27.6	29.1	30.3	2.58	44.4	5.10	59.8	18.6
	Chang 8	14.6	1.37	27.8	25.5	30.5	2.24	49.3	4.85	64.7	25.3
Average value		13.2	1.19	29.3	30.8	28.9	1.74	42.5	3.72	56.4	20.7

Because the pores in the reservoir can be mobilized, all the large pores in the A configuration region can be mobilized, and a large part of the pores in the B configuration region are in the movable range. Therefore, considering the maximum mercury inlet saturation of pores in the A configuration section, Equation (5) can be rewritten as:

$$E_R = E_{R-A} + E_{R-B} = \frac{(S_{Hg-A} - S_{or})}{S_{oi}} \times 100\% + \frac{(S_{oi} - S_{Hg-A})}{S_{oi}} \times 100\% \quad (6)$$

In the formula: E_{R-A} -Large pore recovery component, %; E_{R-B} -Small pore recovery component, %; S_{Hg-A} -Maximum mercury inlet saturation in large pore, %.

Formula (6) divides the recovery factor into two parts, namely, the large pore recovery component and the small pore recovery component.

By substituting the reservoir irreducible water saturation of 29.3%, residual oil saturation of 30.8% and final displacement efficiency of 56.4% into Formula (6), the following results can be obtained:

$$E_{R-A} = \frac{(S_{Hg-A} - 30.8\%) \times 100\%}{70.7\%} \quad (7)$$

$$E_{R-B} = E_R - E_{R-A} = 56.4\% - \frac{(S_{Hg-A} - 30.8\%)}{70.7\%} \times 100\% \quad (8)$$

Formulas (7) and (8) shows that the large pore recovery component and small pore recovery component can be estimated by using the maximum pore mercury inlet saturation of the A configuration section, combined with irreducible water saturation, residual oil saturation and displacement efficiency of Y oilfield.

Using Formulas (7) and (8) and combining with the data of Table 2, large pore recovery component, small pore recovery component and small pore to large pore recovery component ratio were estimated (Table 4). As can be seen, the average large pore recovery component is 33.1%, the average small pore recovery component is 23.3%, and the average small pore to large pore recovery component ratio E_{R-B}/E_{R-A} is 70.4% of the three samples. This shows that the small pores in the reservoir not only occupy a considerable proportion, but also have a great contribution to oil and gas production. In addition, from 1#→2#→3# samples, the higher small pore to large pore recovery component ratio E_{R-B}/E_{R-A} . This means, with the deterioration of reservoir physical properties, the greater the contribution of small pores to oil and gas production.

Table 4. Comparison table of reservoir recovery efficiency between large and small pores.

Sample	Porosity/%	Permeability/ 10 ⁻³ μm ²	Configurational Region	Maximum Pore Inlet Mercury Saturation/%	Recovery Component/%		Recovery Component Ratio/%
					E _{R-A}	E _{R-B}	E _{R-B} /E _{R-A}
1#	14.2	1.22	A	63.28	45.9		
			B			10.5	22.8
2#	12.27	0.828	A	56.13	35.8		
			B			20.6	57.5
3#	9.77	0.331	A	43.17	17.5		
			B			38.9	222.6
Average value					33.1	23.3	70.4

4.3. Ideas and Challenges of Collaborative Simulation

According to the analysis in Sections 4.1 and 4.2, reservoir space is composed of both large and small pores. The ball-and-stick model is suitable for simulating large pores, and the capillary model is suitable for simulating small pores. At the same time, the oil and gas fluids in the large and small pores are mobile (the large pores can be fully used, and the small pores can be partially used), which has a substantial contribution to production. Therefore, it is limited to use a single model (ball-and-stick model or capillary model) in reservoir pore-throat network simulation, and it is very important to integrate the ball-and-stick model and capillary model organically and coordinate the simulation according to the composition ratio. Collaborative simulation will help to establish a more objective and perfect model of reservoir pore-throat network, and on this basis, the simulation of reservoir seepage law will be more comprehensive and accurate.

However, collaborative simulation requires tradeoffs between computational costs and model complexity, as well as technical challenges. Among them, the ball-and-stick model has the advantages of simple calculation, low calculation cost and model complexity, high technical maturity, and relatively mature scale application. However, when dealing with small size and scale but large number of small pores, the capillary model faces the problems of high computational cost and model complexity, especially in the high-precision identification of small pores, fidelity and the processing of the connection relationship

between small pores and large pores. Therefore, how to realize the high-precision identification and fidelity of small pores and how to deal with the connectivity between small pores and large pores is the key to the success of collaborative simulation.

5. Conclusions

The ball-and-stick model is suitable for large pore simulation, especially when dealing with large pores and high permeability reservoirs. Capillary model is more suitable for small pore simulation, especially when dealing with small pores and low permeability reservoirs. The combination of ball and stick model and capillary model, and the collaborative simulation according to the composition ratio, will help to establish a more objective and perfect reservoir pore-throat network model.

Author Contributions: Conceptualization, J.D., X.L., X.Z., Z.P., X.S., Y.S. and S.P.; methodology, J.D.; software, X.L.; validation, X.Z.; formal analysis, S.P.; investigation, J.D.; resources, Y.S.; data curation, X.S.; writing—original draft preparation, J.D.; writing—review and editing, X.Z.; visualization, Z.P.; supervision, X.L.; project administration, J.D.; funding acquisition, J.D. All authors have read and agreed to the published version of the manuscript.

Funding: This research was funded by National Major Science and Technology Project, grant number (2017ZX05035004).

Data Availability Statement: Data are contained within the article.

Acknowledgments: The authors express their gratitude to other authors for their support in the experimental methods, experimental materials and amendments to the content of the article.

Conflicts of Interest: All authors declare that the research was conducted in the absence of any commercial or financial relationships.

References

- Li, C. Effect of pore-throat ratio on reservoir permeability. *Pet. Geol. Recovery Effic.* **2007**, *5*, 78–79+87+116.
- Ruan, Z.; Xu, R.; Wang, J.; Chang, Q.; Wang, D.; Wang, J.; Zhou, G.; Yu, B. Micro-pore structure characteristics of the Paleogene sandstone reservoirs and genesis of microscopic tight zones in the Mahaidong area, Qaidam Basin. *Oil Gas Geol.* **2024**, *45*, 1032–1045.
- Wu, X.; Xiao, Z.; Zhang, Y.; Wang, F.; Zhao, J.; Fang, C. Progress and Prospect of Multiscale Digital Rock Modeling. *J. Jilin Univ. (Earth Sci. Ed.)* **2024**, *54*, 1736–1751.
- Li, J.; Liu, Y.; Gao, Y.; Cheng, B.; Meng, F.; Xu, H. Effects of microscopic pore structure heterogeneity on the distribution and morphology of remaining oil. *Pet. Explor. Dev.* **2018**, *45*, 1043–1052. [[CrossRef](#)]
- Zhao, W.; Wu, K.; Jiang, L.; He, M.; Li, X.; Jia, C. Charging and microscopic gas-water occurrence characteristics of tight sandstone gas based on pore network model. *Nat. Gas Ind.* **2022**, *42*, 69–79.
- Wu, J.; Wang, R.; Yang, C.; Zheng, S.; Chen, D.; Zong, T.; Wang, Y. Micro nano pore throat CT imaging ball stick model of tight sandstone gas reservoir in Ordos Basin. *Prog. Geophys.* **2023**, *38*, 337–347.
- Chen, M.; Hou, Y.; Wang, P.; Liu, X.; Wang, Z. Quantitative characterization of reservoir micro-pore structure based on digital core—A case study of Penglai 19-3 Oilfield in Bohai Sea. *Pet. Geol. Eng.* **2024**, *38*, 82–89.
- Zou, C.; Zhu, R.; Bai, B.; Yang, Z.; Wu, S.; Su, L.; Dong, D.; Li, X. First discovery of nano-pore throat in oil and gas reservoir in China and its scientific value. *Acta Petrol. Sin.* **2021**, *27*, 1857–1864.
- Zhu, R.; Wu, S.; Cui, J.; Bai, B.; Yang, Z.; Hui, X.; Feng, J.; Su, L.; Shi, W.; Wang, X. Classification and Evaluation of Pore Size in Oil & Gas Reservoir Rocks. *Bull. Geol. Sci. Technol.* **2016**, *35*, 133–144.
- Wang, H.; Shi, Y.; Xu, D.; Chen, X.; Li, L. Unconventional reservoir pore structure characterization techniques and progress. *Pet. Geol. Recovery Effic.* **2019**, *26*, 21–30. [[CrossRef](#)]
- Song, Y.; Han, D.; Pang, Z.; Song, Z.; Dong, Y. Spatial configuration cognition and renewal implementation decision-making of residential historical districts. *Urban Plan. Int.* **2024**; in press.
- Zhu, L. Research on the optimal configuration of steel bridge based on topology optimization. *J. Henan Univ. (Nat. Sci.)* **2019**, *49*, 612–617.
- Guo, Q.; Deng, Z.; Jin, S. Inheritance and development of classic configuration: Terminal renovation and expansion of Jieyang Chaoshan international airport. *Archit. Tech.* **2021**, *27*, 78–80.

14. Wang, D.; Yi, W.; Meng, Y. Research on motion configuration and joint control system of reconfigurable manipulator. *Mach. Electron.* **2020**, *38*, 53–57.
15. Zhang, X.; Chen, B. Research progress on microstructure, defects, surface and configuration of additive manufactured typical aviation metals. *J. Aeronaut. Mater.* **2024**, *44*, 1–14.
16. Ren, Y.; Wu, X. Preliminary study on the context spatial unit and its configuration mode of the famous historical and cultural cities. *Urban. Archit.* **2020**, *17*, 81–83.
17. Allen, J. The plan shape of current ripples in relation to flow conditions. *Sedimentology* **1977**, *24*, 53–62. [[CrossRef](#)]
18. Ren, Y.; Zhao, J.; Chen, J.; Guan, X.; Song, J. Sedimentary characteristics and sand body architecture of shallow delta front in Ordos basin: A case study of Chang 9 member in Shiwanghe section in Yichuan. *Xinjiang Pet. Geol.* **2022**, *43*, 310–319.
19. Guo, Y.; Feng, W.; Li, S.; Yan, S. Sedimentary architecture between compound middle bars and side bars: Insights from a numerical model of sandy braided rivers. *Adv. Earth Sci.* **2024**, *39*, 405–418.
20. Zhu, X.; Chen, H.; Ge, J.; Tan, M.; Liu, Q.; Zhang, Z.; Zhang, Y. Characterization of sequence architectures and sandbody distribution in continental rift basins. *Oil Gas Geol.* **2022**, *43*, 746–762.
21. Wu, Z.; Ke, X.; Zhang, P.; Wen, F.; Tong, Q.; Liu, L. Sand body architecture of Chang 9 member in Jiyuan area, Ordos basin. *Xinjiang Pet. Geol.* **2022**, *43*, 294–309.
22. Wang, J.; Xi, Z.; Lu, D. Pore structure of shale gas reservoirs revealed by constant-speed mercury injection experiments: A case study of Wufeng formation shale from northwestern Hunan province. *Geol. Explor.* **2021**, *57*, 450–456.
23. Dai, J.; Li, J.; Ren, Q.; Mu, Z. Microscopic characteristics of Chang 8 low permeability tight reservoir in Xifeng oilfield. *Sci. Technol. Eng.* **2019**, *19*, 118–125.
24. Li, W.; Zhang, Y.; Wang, F.; Zhu, J.; Ye, B. Application of constant-rate mercury penetration technique to study of pore throat characteristics. *Lithol. Reserv.* **2012**, *24*, 60–65.
25. He, T.; Wang, F.; Wang, L. Characteristics of micro-pore structure of tight sandstone reservoir: A case study from Chang 7 reservoir of Yanchang Formation in Ordos Basin. *Lithol. Reserv.* **2013**, *25*, 23–26.
26. Zhang, X.; Zhang, J.; Yuan, J.; Cui, X.; Mao, Z. Micro pore throat structure and its influence on seepage of Chang 81 tight reservoir in Nanliang-Huachi area, Ordos Basin. *Lithol. Reserv.* **2021**, *33*, 36–48.
27. Wang, S.; Javadpous, F.; Feng, Q. Confinement correction to mercury intrusion capillary pressure of shale nanopores. *Science* **2016**, *6*, 1–12. [[CrossRef](#)]
28. Dai, J.; Lin, L. “Seepage” classification scheme of reservoir pores and its significance. *Pet. Geol. Oilfield Dev. Daqing* **2022**, *41*, 43–50.
29. Wu, Y.; Wu, S. *Oilfield Geology*, 4th ed.; Petroleum Industry Press: Beijing, China, 2011; pp. 190–191.
30. Wu, S. *Reservoir Characterization and Modeling*; Petroleum Industry Press: Beijing, China, 2010; pp. 181–182.
31. Yang, S.; Wei, J. *Fundamentals of Petrophysics*; Petroleum Industry Press: Beijing, China, 2004; pp. 222–224.

Disclaimer/Publisher’s Note: The statements, opinions and data contained in all publications are solely those of the individual author(s) and contributor(s) and not of MDPI and/or the editor(s). MDPI and/or the editor(s) disclaim responsibility for any injury to people or property resulting from any ideas, methods, instructions or products referred to in the content.