A Multi-element least square HDMR methods and their applications for A multiscale-multiphase model

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Abstract

After fracturing operation, hydraulic fractures and induced fractures are created within the shale reservoir. A lot of treatment water is stored in fractures network and flow back into the surface during the gas recovery process. The gas production performance is affected by the water flowback because two phase flow occurs within fractures zone. For the created reservoir scale, we propose a multiscale- multiphase simulation model, which defines the whole domain as three sections. Section A contains the organic and inorganic matrix, which stores both the free gas and adsorbed gas. Flow processes are defined in the components of inorganic minerals and kerogens, respectively. For the section B and C, gas phase and water phase are existed together. Under this framework, a set of partial differential equations are derived to define various liquid transport processes: (1) gas flow in the kerogen system of matrix; (2) gas flow in the inorganic system of matrix; (3) gas-water two phase flow in fractures zone and (4) gas-water two phase flow in the hydraulic fracture system. Dynamic permeability models and mass exchanges between them are coupled for all systems. The model was verified against field production data from the Barnett Shale. Model simulation results show that flowback of treatment water can significantly affect the gas production rate at the early stage. Firstly, the increase of maximum water relative permeability can raise the water flowback rate and gas production rate but increasing non-wetting phase entry pressure will decrease the fluids flow rate. Secondly, the impact of fractures zone width on gas production performance is unstable and increasing initial water saturation can increase the water flowback rate but decrease gas production rate. Overall, the dynamic performances of water phase within fractures zone have significant impact on the short and long time shale gas recovery.

Keywords

Two phase flow; Multiscale; Shale gas; Reservoir simulation; Water flowback.

1. Introduction

In order to improve the unconventional natural gas recovery for shale reservoirs, hydraulic fracturing and horizontal well are the key approaches to be applied in field production. Hydraulic fracturing can create many bigger fractures within the reservoir and increase the contact area of matrix to the high permeability areas. In the previous study [1] the whole reservoir simulation is divided into two sections. One is the hydraulic and induced fractures and the other is shale matrixes between hydraulic fractures. The fully coupled model can predict the shale gas production performance accurately. However, it ignored the impact of the water flowback on the gas production behaviors, which makes that the prediction of reservoir simulation is a little higher than the actual field data at the early stage of production[1]. In this study, we proposed an improved multiscale-multiphase simulation model for shale reservoirs, which takes the impact of water flowback into account. The whole domain is divided into three sections namely section A, section B and section C on the basis of different flow mechanisms as shown in Figs. 1and 2. For the evaluation of shale gas recovery, it is critical to consider the different flow mechanisms within different scales.

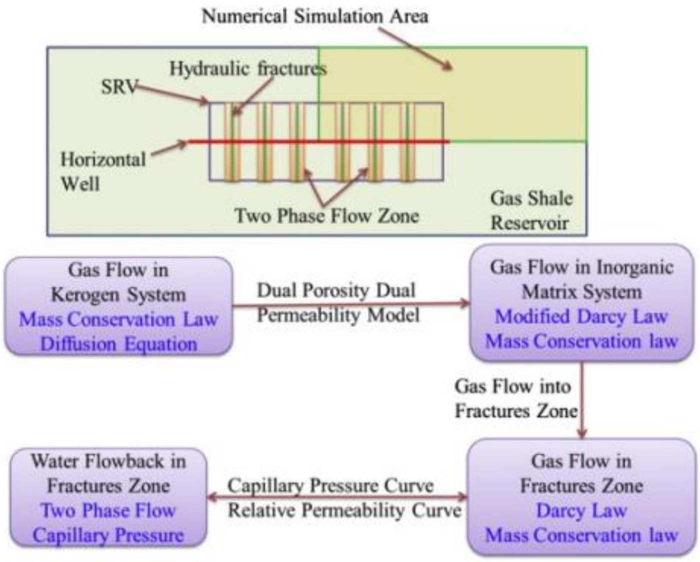

Fig. 1. Interactions and relationships among different systems in shale gas reservoir.

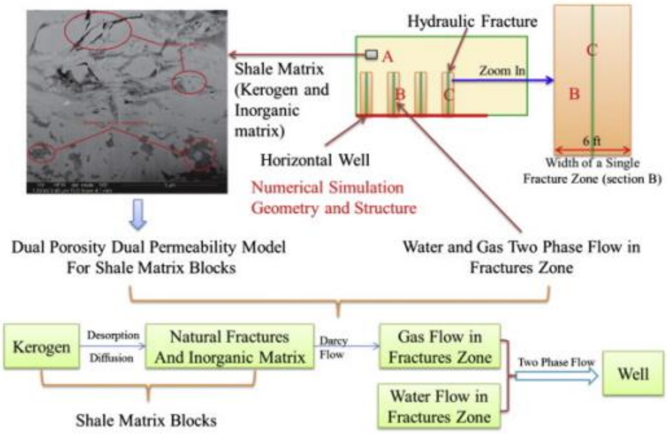

Fig. 2. Numerical simulation model for the shale reservoir (SEM graph from [2].

Continuum mechanics theory is applied to investigate the gas transport within shale reservoirs for many years. Both the single porosity single permeability model [3] and dual porosity dual permeability model [4-7] are used to analyze the gas transport behaviors. The single porosity model ignores the differences between kerogen system and inorganic matrix system. Thus, dual porosity model seems more applicable for the gas shale reservoirs because there are many differences between inorganic matrixes and kerogens[8-9]. For both the kerogen and inorganic matrix, slippage effect is an important factor for gas transport mechanisms. Thus, dual porosity dual permeability model is used to formulate the gas mass transfer mechanisms for section A. The dynamic permeability models for kerogen and inorganic matrix have considered the impact of flow regimes on the permeability[10-12]. When the compressibility of matrix is very lower, the impact of effective stress on the permeability in section A can be ignored [13]. It is noticed that most reservoir simulation models for unconventional natural gas extraction ignore the operation of water flowback, which makes the prediction of gas production deviates from the field data. In this study, we focus on the impacts of water flowback on the gas recovery performance.

During the treatment of shale reservoir, tens of thousands of barrels of water are injected into a single well. 10–50% of the injected water can be recovered during the clean-up stage and initial period of production[14-16]. Most of the water will be retained in the fractures zone of reservoir. During the gas production operation, water can flow back into the horizontal well and it affects the gas production. The retained water will increase water phase saturation and consequently decrease gas saturation and gas flow ability[17-18]. Some filed tests and observations show that post fracturing shut in may reduce water recovery and help gain higher production rates [17]; [19-21]. Some researchers adopt the flowback data of water and gas to analyze the properties of hydraulic fractures and address the long term prediction of shale gas[22-25]. Clarkson and Williams-Kovacs [24] proposed a two phase tank model for shale to predict the water flowback rate and gas production rate. However, the real impact of retained water on production performance of shale gas wells in not fully understood. In this study, gas-water two phase flow mechanism by analogy of black oil model is applied in the fractures zone (section B). Based on this model, the impacts of water flowback on the gas production performance are investigated. For most shale reservoirs, water is the wetting phase to shale matrix and fractures and gas is the non-wetting phase. For the hydraulic fractures (section C), fracture flow model is applicable to describe the gas and water transport into the horizontal well. And experimental results indicate the absolute permeability of the fractures decreases with the decrease of gas pressure[26-27].

Generally, we establish a multiscale-multiphase simulation model for shale reservoir. Based on the conventional dual porosity dual permeability model for section A, we add two phase flow into the fractures zone (section B and C). Capillary pressure and relative permeability curve are coupled in the numerical mode. Based on this reservoir simulation model, we analyze the impacts of water flowback performance on the gas production such as the properties of two phase zone as discussed below.

2. Simulation

The capillary pressure curve and relative permeability curve are show as Figs. 3 and 4.

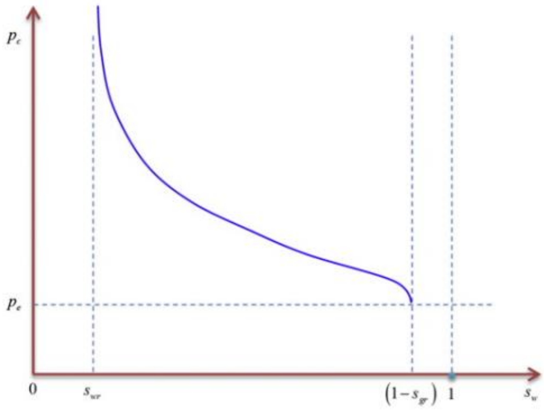

Fig. 3.Capillary pressure versus water saturation within two phase flow zone.

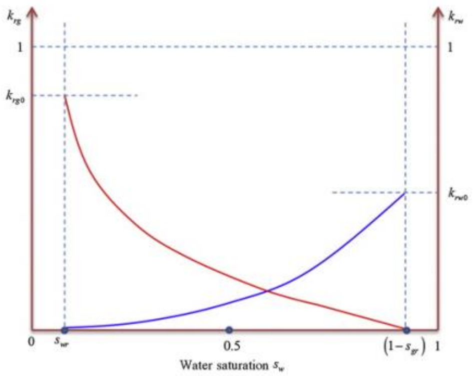

Fig. 4. Relative permeability curves of gas and water for two phase flow zone.

The comparison between the filed data and the simulation results are shown in Fig. 5. It is noticeable that the model results are in good agreements with the production data. Now, the gas production rate in the early days from the simulation is similar to the actual field data. Then, the gas rate decreases from the peak point to6×104 m3/d at 250 days. For the water flowback, the rate decrease from 300 at peak point to 38 m3/d at the 250 days and then reach to almost zero after 1000 days production as shown in Fig. 6.

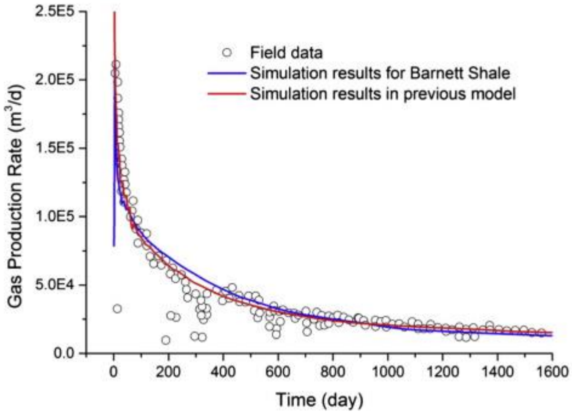

Fig. 5. Comparison between field data and simulation results in Barnett Shale.

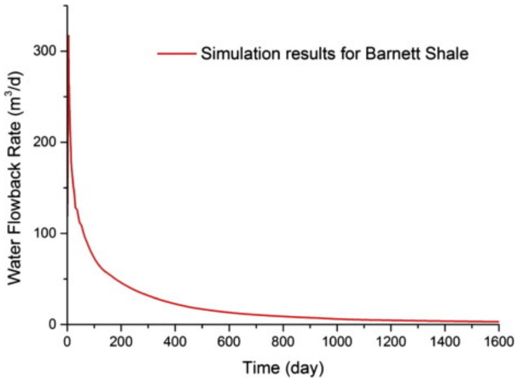

Fig. 6. simulation results of water flowback rate for Barnett Shale.

It is clearly seen that the inorganic matrix pressure (unit Pa) evolution of the Barnett Shale from Fig. 7. The whole gas transport process involves different flow mechanisms and different scales as shown in Figs. 1 and 2. The drainage area of gas becomes bigger when the natural gas is extracted from the reservoir. From Fig. 7, we can see the pressure distribution is dynamic and the fractures zone is the main flow path.

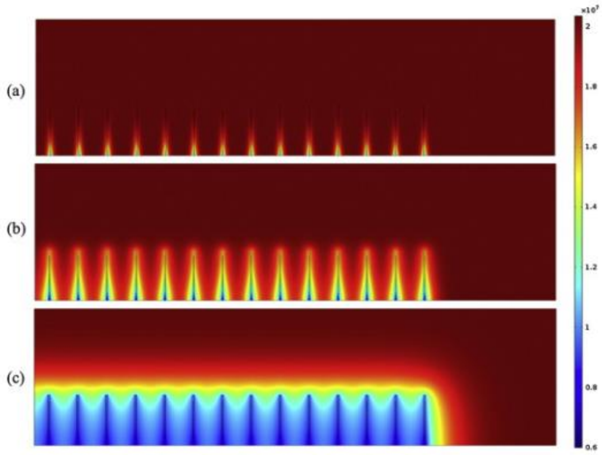

Fig. 7. The gas pressure (Pa) distribution of inorganic matrix for Barnett Shale at different times (a) after 10 days of extraction; (b) after 100 days; (c) after 1000 days.

From the simulation, we can obtain the evolution and distribution of gas pressure, water pressure and water saturation in Barnett Shale. The simulation domain is a two dimensions area and we cut one line D-E and one point F in the geometry to see the evolution of properties. The positions and coordinates of line and point are shown in Fig. 8. The line starts from point E (0 m, 40 m) to point E (500 m, 40 m), which pass through the 14 hydraulic fractures (section C) and fractures zone (section B). The coordinates of point F is (15 m, 25 m).

As shown in Fig. 9, the gas pressure in inorganic matrix system undergoes a decreasing trend when the gas is depleted from shale reservoir. The gas pressure outside of fractures zone will drop slowly and it is corresponding to the drainage area evolution as shown in Fig. 7.

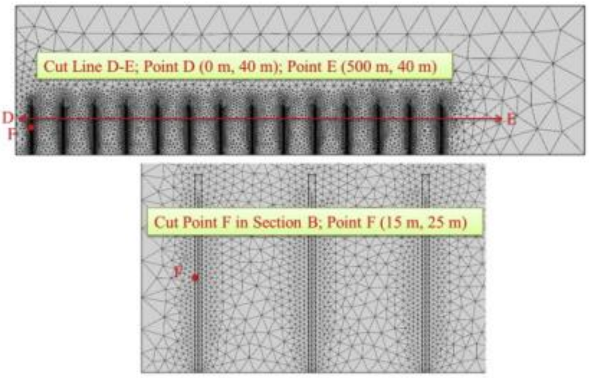

Fig. 8. Position of line D-E and point F in the simulation geometry.

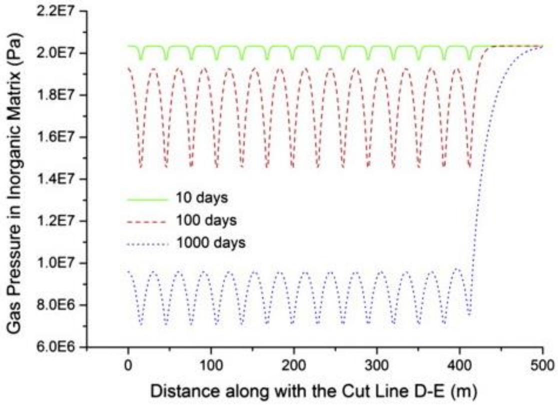

Fig. 9. Gas pressure evolutions in inorganic matrix along the line D-E.

When we see the evolution of water phase properties in fractures zone, we obtain that the water pressure experiences a decreasing trend for point F as shown in Fig. 10. The water pressure changes from 20 MPa at the early stage to below 5 MPa after 2000 days, which means the water flowback rate will decline as shown in Fig. 6. When the water phase saturation decreases with time, the relative permeability for water also undergoes the decreasing trend as shown in Fig. 11. The relative permeability at point F is only 0.6 at the initial condition and the value is below 0.2 when the production continues to 2000 days. Conversely, the gas relative permeability rises from less than 0.1 at the first days to almost 0.4 after 5 years' depletion as shown in Fig. 11.

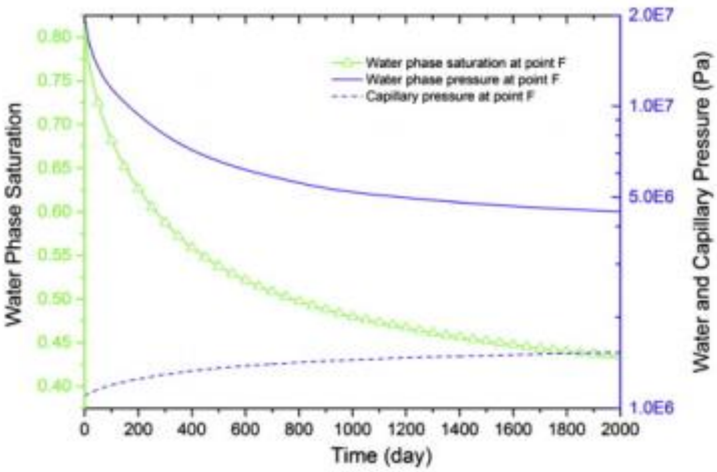

Fig. 10. Evolution of water phase properties and capillary pressure at point F.

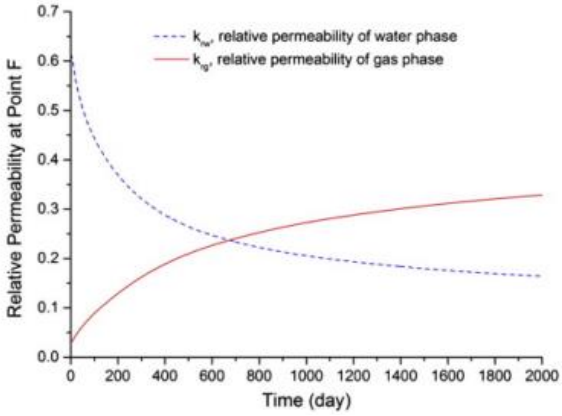

Fig. 11. Evolution of relative permeability for both water and gas phase at point F.

3. Results And Discussion

In order to create more complex fractures network in shale reservoirs, we need to inject more fractured water with higher pressure into fractures zone. Then the width of a single fracture zone (section B) will be different as shown in Fig. 2, which can represent the volume of treatment water. Different width of the fracture zone means different injected treatment water volume in the shale reservoir, which affects the water gas two phase flow mechanisms and the gas production performance. The width of a fracture zone is set as 1.83 m (6 ft) in the base case (scenario one) of Barnett Shale as shown in Fig. 2. The bigger width leads to higher fractured water volume in fractures. We present two other scenarios of width namely 1.52 m (5 ft) and 2.13 m (7 ft) to analyze the impact of fractured water content on the production performance of shale gas reservoir. The evolution of gas production rate and water flowback rate for the three scenarios are shown in Fig. 12. It is noticeable that the impact on gas production rate is unstable. The gas production rate from the scenario 2.13 m is the highest but reduces to the lower magnitude after 400 days production while the cumulative gas production of base case (1.83 m) is the lowest among the three cases as shown in Fig. 13.

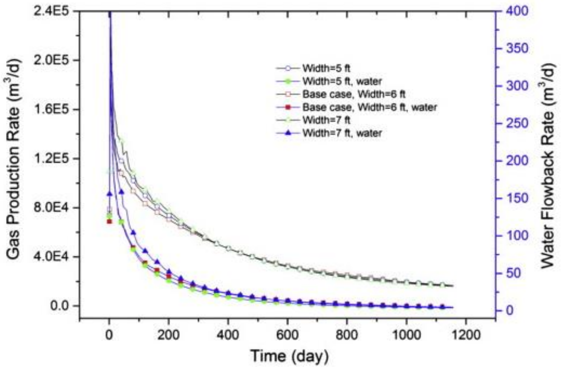

Fig. 12. Evolution of gas and water production rate under different width of fractures zone.

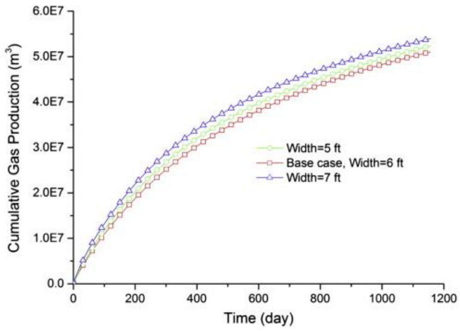

Fig. 13. Impact of width of fracture zone on the gas production behaviors.

Two phase flow in porous medium is a hot topic in many research areas. The maximum relative permeability for gas can be assumed to be one while the maximum relative permeability for water k*rw*0 is usually less than one because of the wettability as shown Fig. 4. Thus, the relative permeability curve is different when the wettability of shale rocks changes. The simulation results of the three scenarios are shown in Fig. 14.For the cumulative gas production of the three scenarios, the high maximum relative permeability for water phase also corresponds to the high gas production as shown in Fig. 15.

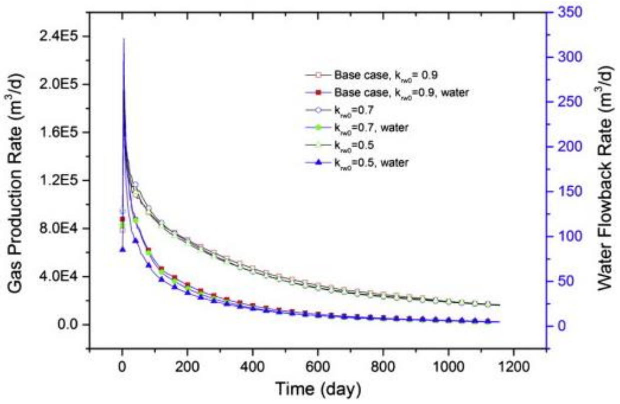

Fig. 14. Evolution of gas and water production rate under different maximum water relative permeability.

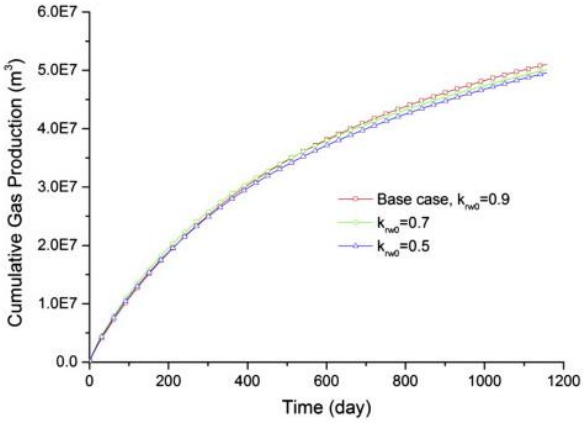

Fig. 15. Impact of relative permeability curve on the gas production behaviors.

The simulation results of the three scenarios are shown in Fig. 16. It is obtained that increasing non-wetting phase entry pressure can decrease both the water flowback rate and gas production rate in shale reservoir. The gas production rate decreases from over5.7×104 m3/d for Pe = 1 MPa to almost 3.6×104 m3/d for Pe = 4 MPa at the time of 300 days of extraction. At the same time, the water flowback rate decreases from 31 m3/d to 21 as shown in Fig. 16. When the capillary pressure curve changes, the impact of water flowback on the cumulative gas production is significant and the high water phase entry pressure means lower gas production as shown in Fig. 17. It is noticed that for the field production, the capillary pressure curve has a close relationship with shale rock properties and fractures network, which means it is difficult to change the capillary pressure curve for shale gas reservoir.

After hydraulic fracturing operation, most water is stored in fractures zone. The simulation results of the three scenarios are shown in Fig. 18. It is obtained that increasing initial water saturation can increase the water flowback rate but decrease gas production rate in shale reservoir at the early stage of extraction as shown in Fig. 18. The water flowback rate has the similar trend in the whole life of production. When the water saturation is bigger than 0.8, the impact of water flowback on the gas production is reflected at the early stage of recovery as shown in Fig. 19.

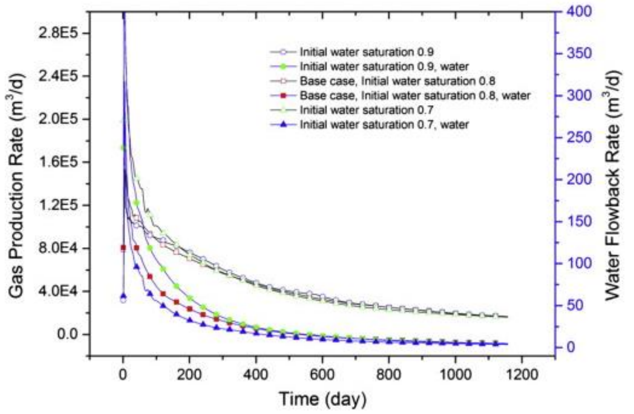

Fig. 18. Evolution of gas and water production rate under different initial water saturation.

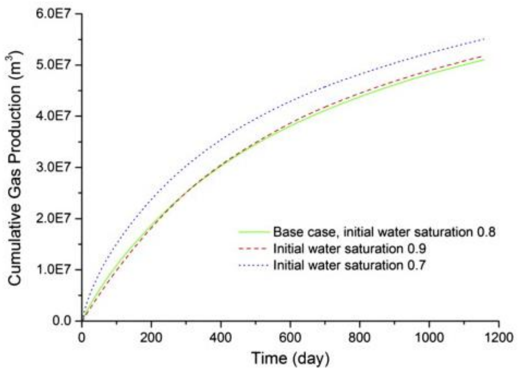

Fig. 19. Impact of initial water saturation on the gas production behaviors.

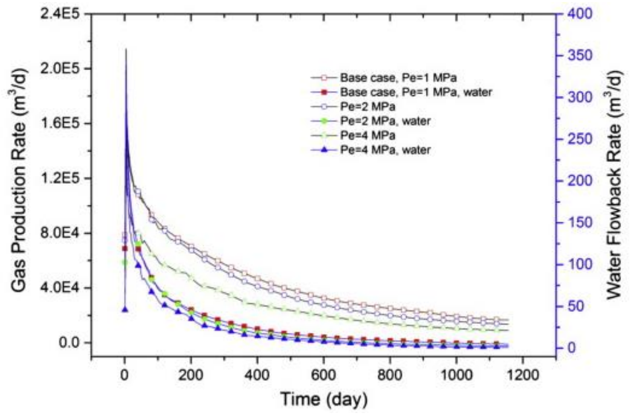

Fig. 16. Evolution of gas and water production rate under different capillary pressure curves.

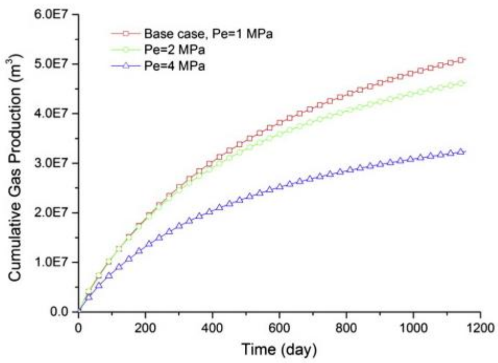

Fig. 17. Impact of capillary pressure curve on the gas production behaviors.

4. Conclution

(1)The flowback of treatment water can significantly decrease the gas production rate at the early stage of shale reservoir. Both the water flowback rate and gas production rate will increase at the early days of extraction then drop to a very lower magnitude (less than one half of the maximum rate) after one year's production. The water pressure and gas pressure in fractures zone undergo decreasing trends when the liquids are produced from the well. The relative permeability of gas phase increases when the water phase saturation decreases with water flowback.

(2)The gas production behaviors have close relationships with water phase properties. Increasing maximum water relative permeability can increase both the water flowback and gas production rate for shale reservoir because it can enhance the water flow ability of fractures zone. Increasing non-wetting phase entry pressure can decrease both the water flowback and gas production rate because the increase of entry pressure means increasing the resistance of two phases flow. However, the impact of increasing fractures zone width (treatment water volume) on gas production performance is unstable because of two reasons as discussed above.

(3)For shale gas reservoirs, shut in is an important operation step in field production. Imbibition mechanism during shut in period can reduce the initial water saturation for fractures zone. Increasing initial water saturation can increase the water flowback rate but decrease gas production rate in shale reservoir at the early stage of extraction. The impact of water flowback on the gas production at the late stage of production is very weak.

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