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New Methods for Controlled Reserves Analysis in tight oil reservoirs

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This paper describes the physical model of a multi-stage fractured horizontal well in tight reservoirs. Moreover, a composite zonal productivity prediction model of staged multi-cluster fracturing horizontal well was established. The inner area of the model is a dual porosity model composed of matrix and micro-fracture network formed by the artificial fracture and natural fractures opened by fracturing treatment, and the outer region is a single matrix. The effects of threshold pressure gradient, stress-sensitive matrix permeability, capillary pressure, and the conductivity failure capacity of artificial fractures in the production forecast are fully considered in the model. The influence of different clusters, different fracturing stages, half-length of fractures, and permeability of the micro-fractures on the oil drainage area of the horizontal well was analyzed via numerical simulation. The influencing factors of different well patterns and drainage area of multi-stage fractured horizontal well were also studied. The method of using drainage radius of multi-stage fractured horizontal well and the technical countermeasures to improve the well productivity are instructive for the development of tight oil reservoirs.

1. Introduction

Given that Stimulated Reservoir Volume (SRV) fracturing treatment was recently implemented, it is still in the exploratory stage, so the model does not consider reservoir geologic characteristics and seepage field characteristics after fracturing in tight reservoirs. Therefore, further research on the productivity model of this kind of horizontal well is necessary. The traditional seepage model cannot be characterized, and failure of hydraulic fractures has not been effectively characterized. In 1988, on the basis of the seepage resistance method, Mercer and Pratt (1988) proposed a method for predicting the steady-state productivity of a fractured horizontal well; their model considered radial flow in the fracturing zone, linear flow of the matrix to the fracture, internal linear flow of the fracture, and radial flow at the intersection of the fracture and wellbore. Tinsley et al. (1969) studied the linear and radial flow of non-Darcy flows, expressed the nonlinear flow relationship with the Forchheimer and Baree–Conway equations, and analyzed the effect of water phase saturation on the final yield. Prats (1961) and prats (1962) used a semi-analytic mathematical model to describe fluid flow, considered the impact of fluid on the fracture in flow, described the pressure distribution of the multistage fracturing horizontal well, and concluded that the effectiveness of the horizontal well is related to the length of horizontal wells and number of fractures.
The reservoir utilization range is one of the key points in reservoir engineering research. The accurate determination of the shape and range of use of the reservoir has an important impact on rational well placement, optimizing fracturing treatment, and enhancing oil recovery in the later stage. Many methods can be used to study the law of drainage area, such as the unstable pressure test method, material balance method, decline analysis method, and numerical simulation.
In the late 1980s, Joshi (1990) first introduced the drainage area calculation method for the horizontal well in homogeneous and heterogeneous reservoirs and analyzed the influence of the drainage area on horizontal

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well productivity. Saavedra and Reyes (2001), based on Joshi's research, analyzed the influence of pressure decline in the horizontal wellbore on the drainage scope. Reisz (1992) then used the production decline curve to study the horizontal well utilization scope; their results demonstrated that reservoir physical properties influence the drainage scope, and horizontal wells should consider the influence of reservoir physical properties. Vo and Madden (1993) conducted pressure instability well tests and actual production dynamic data to study the drainage scope of horizontal wells. Combined with actual production data, England and Poe, (2000) pointed out that the fracture half-length and fracture conductivity are the main influencing factors of a tight gas reservoir drainage range; when the fracture half-length is less than 1,000 feet, the effect of conductivity is small. Guillermo Alzate et al. (2001) used numerical simulation methods to analyze the effect of fracture length, conductivity, reservoir properties, and reservoir heterogeneity on the drainage scope of a tight gas reservoir vertical well at different times; they reported that the fracture half-length is the main sensitive factor of the drainage scope. Mohammad Sadeghi et al. (2013) combined well tests with improved IPR curves and proposed a method for determining the range of vertical wells used in fractured reservoirs. Compared with other methods, this method is simple, fast, and reliable. A. Taheri and S.R. Shadizadeh studied vertical and horizontal wells and reviewed different methods for determining the draining scope. They also reported that the use of the pressure distribution method to predict the draining scope is accurate.

In 2007, Li Zhongping et al combined the characteristics of tight sandstone gas reservoir development, analyzed the influencing factors of the difficulty of its reserves, discussed the influence of the developed natural fractures on the development of tight gas reservoirs, and proposed technical countermeasures to improve the utilization degree of tight gas reservoirs. On the basis of seepage mechanics theory, in 2010, Zhu Weiyao et al. derived the mathematical model of seepage flow in non-Darcy flow of low/extra low permeability reservoir fluids, proposed a method of determining the radius of the fracturing treatment well, and examined the relationship between the threshold pressure gradient and radius of the driving force under various production pressure differences. Subsequently, they clarified the calculation method of different well network kinetic coefficients. With the dual-porosity reservoir as the research object, in 2011, Yang Shenglai et al analyzed the mechanism of matrix on pressure drainage scope; and the result demonstrate that the more natural fractures develop, the higher the drainage area. From the survey of the drainage scope, the range of different well types in conventional and unconventional reservoirs was studied, while the influence of threshold pressure gradient was not taken into account. However, many research considered the effect of threshold pressure gradient on drainage scope, and only the direct well was studied. In the present study, the influencing factors of drainage scope volume were studied for multi-stage fracturing horizontal well. The drainage radius and effective drainage area of different well types were evaluated, as well as the controlled dynamic reserves.

2. Model description

2.1 Mathematical Formulation

2.1.1 Inner Dual-Porosity System

We use Warren-Root dual-porosity model (1963)[13] to simulate fracture networks flow. The reservoir model is represented by two overlapping continua-fracture networks and matrix blocks. The interaction between the two continua is controlled through a transfer factor α.

The underlying assumptions of the reservoir model are as follows: (1) the model is three dimensional and two-phase(oil and water phase); and (2) follows non-Darcy flow, only with the oil phase start-up pressure gradient considered; (3) permeability and porosity change as formation pressure varies; (4) the reservoir fluids are compressible and with constant compressibility factors; (5) the gravity pressure are ignored; (6) the wells produce at constant bottom hole pressure.

oil phase: $$\nabla[\rho_o \frac{k_m k_{ro}}{\mu_g}(\nabla p_m - G_o)] + \frac{\alpha \rho_o k_m k_{ro}}{\mu_o}(P_{sf} - P_m) = \frac{\partial(\rho_o s_o \phi)}{\partial t} \tag{1}$$

water phase: $$\nabla[\rho_w \frac{k_m k_{rw}}{\mu_w}(\nabla P_m - G_w)] + \frac{\alpha \rho_w k_m k_{rw}}{\mu_w}(P_{sf} - P_m) = \frac{\partial(\rho_w s_w \phi)}{\partial t} \tag{2}$$

oil phase: $$\nabla[\rho_o \frac{k_{sf} k_{ro}}{\mu_o}\nabla p_{sf}] + \frac{\alpha \rho_o k_m k_{ro}}{\mu_o}(P_m - P_{sf}) = \frac{\partial(\rho_o s_o \phi)}{\partial t} \tag{3}$$

water phase: $\nabla[\rho_w \frac{k_{sf} k_{rw}}{\mu_w} \nabla p_{sf}] + \frac{\alpha \rho_w k_m k_{rw}}{\mu_w}(P_m - P_{sf}) = \frac{\partial(\rho_w s_w \phi)}{\partial t}$ (4)

where

$$G_o = a\left(\frac{K}{\mu_o}\right)^{-b}, \quad K = K_0 e^{[\alpha(P-P_0)]}, \quad \phi = \phi_0 e^{[\beta(p-p_0)]} \tag{5}$$

respectively, where the subscript f indicates fracture system, m matrix system, P fracture system pressure ,P_o initial pressure of the reservoir,σ is shape-dependent constant, ρ_o is oil density, ρ_w water density, k_f fracture system permeability, k_{ro} oil relative permeability, k_{rw} water relative permeability, μ_a acid viscosity, μ_o oil viscosity, S_o oil saturation, S_w water saturation, and φ porosity.
G is start-up pressure gradient, MPa/m; *a* and *b* are corresponding regression coefficients; α and β are coefficients of permeability and porosity as the reservoir pressure changes, 1/MPa. All the parameters are in SI unit.

2.1.2 The Main Fractures

The underlying assumptions of the fracture model are as follows: (1) the model is two dimensional and two-phase (oil and water phase); (2) the fracture is vertical, with cubic shape; (3) the flow in the fracture follows Darcys law; (4) the fracture flow conductivity varies with time, which is attained through long time fracture conductivity experiments.
the linear flow in dual porosity zone to the fractures and lastly linear flow in the fractures into the wellbore. Eqs.6 is the seepage control differential equation of the fracture:

$$-\frac{\partial}{\partial x}\left(\rho_o V_o\right) - 2\frac{\rho_o V_{y,o}}{W} = \frac{\partial}{\partial t}\left(\rho_o \phi S_o\right) \tag{6}$$

where

$$K_f = K_{f0}\exp(-ct) + K_0 \tag{7}$$

K_f is dynamic fracture permeability and K_{fo} is initial fracture permeability, K_o is initial formation permeability, μm^2; t is time, d; c is the corresponding regression coefficients.

2.1.3 Outer Reservoir

The outer reservoir in our model is a single porosity, 1D linear reservoir. The flow from the outer single porosity reservoir into the inner reservoir is given by the following partial differential equation.

oil phase: $\nabla[\rho_o \frac{k_m k_{ro}}{\mu_o}(\nabla p_m - G_o)] = \frac{\partial(\rho_o s_o \phi)}{\partial t}$ (8)

water phase: $\nabla[\rho_w \frac{k_m k_{rw}}{\mu_w}(\nabla P_m - G_w)] = \frac{\partial(\rho_w s_w \phi)}{\partial t}$ (9)

2.2 Mathematical model solution

Eqs.1- 9 constitute a complete mathematical model to describe the non-Darcy flow in tight oil reservoir. Using IMPES method, the reservoir model and the fracture model are solved separately. Conjugate gradient method is adopted for the seven diagonal linear equations. In order to improve the convergence rate, the computing time step can be selected automatically during the calculation process.

2.3 Simulation model description

On the basis of the previous mathematical model, the basic data of a reservoir (Table 1) were used as a basic case in a tight oil reservoir. The following parametric study for horizontal wells is presented to show how fracture clusters and stages, matrix permeability and fracture length in the affect horizontal well drainage scope. Assuming that the reservoir was a cuboid, its x-, y-, z-direction sizes were 1,500, 600 m, and 10m respectively, and the total area was 9000,000 m^3. The reservoir center had a horizontal well in the x-direction, and the wellbore length was 1,000 m. In the calculation model, the mesh was divided into 150×60×1 grids. In the model, each grid was 10 m, the fracture half-length was 200 m, SRV was 400,0000m^3, and the reservoir area coefficient was 44.4%.

Table 1: Parameter in simulation

Parameter	Value	Parameter	Value
Matrix system permeability(10^{-3}μm^2)	0.1	Oil volume factor(m^3/m^3)	1.5857
Micro-Fracture permeability(10^{-3}μm^2)	30	Oil compressibility(1/MPa)	0.002243
matrix system porosity(%)	8	Water compressibility(1/MPa)	0. 000486
Micro-Fracture porosity(%)	0.3	Rock compressibility(1/MPa)	0.004
Initial water saturation(%)	50.9	Reservoir pressure(MPa)	31.58
Water viscosity(mPa·s)	0.4	Bottom hole pressure(MPa)	20
Oil viscosity(mPa·s)	3.3	Well bore radius(m)	0.1

3. Controlled reserves of different well types under the SRV of volume fracturing treatment

3.1 Controlled reserves of different stages with the same clusters

Figure 1 shows drainage scope reserves in the impact range of fracturing horizontal wells in different stages. The drainage scope reserves of multi-stage fractured horizontal wells increased with the increase in the number of stages. The drainage reserves grew as the fracturing stages increased. As the fracture numbers expanded, seepage resistance decreased and the spread range grew. However, when the number of stages did not change, the distribution of cluster spacing was uniform in each stage, and the drainage reserves of control were large. Figure 2 illustrates the ratio of cumulative oil production to controlled (Liu et al., 2018) reserves at different times of different stages wells. Even if volume fracturing technology greatly improved the drainage scope and reduced resistance, the final degree of recovery remained 10%. Therefore, the remaining oil in the stimulated reservoirs remained high. Outside the stimulated area, tight oil reservoir permeability was low, seepage resistance was large, and an effective area could not easily form where no fracture network was present. The pressure fell fast, and the pressure in the bottom rapidly decreased. As the number of stages decreased, the stimulated reservoir volume fell, the pressure decreased, and the recovery degree was reduced. In addition, a high number of stages under the same cluster number resulted in a large fracturing area; the greater the effective range, the higher oil production. Therefore, in tight oil reservoir, the fracturing stages should be increased to form fracture network and improve cumulative production.

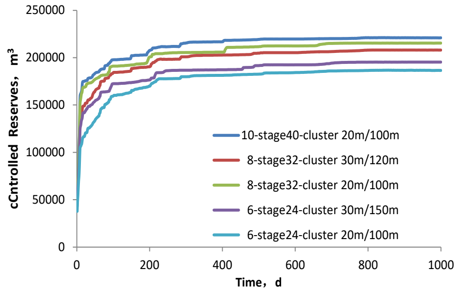


Figure 1: Change in controlled reserves of different stages with time

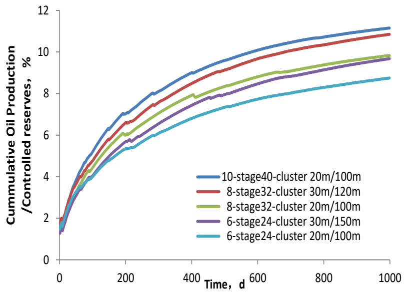


Figure 2: Change in recovery degree of different stages with time

3.2 Controlled reserves of different clusters with the same stages

Figure 3 shows drainage scope reserves in the impact range of fracturing horizontal wells in different clusters. The drainage scope reserves increased with rising clusters, thereby increasing the drainage scope. Figure 4 shows the relationship between cumulative oil production and the controlled reserves at different times of various clusters. For a 10-staged fracturing horizontal well, the drainage scope reserves controlled by two, three, and four clusters in each stage were almost the same. However, the production of four clusters of 10-staged fracturing horizontal wells was far more than those of two and three clusters. Thus, seepage resistance decreased as the number of clusters increased. Moreover, the oil production rose but did not exceed 15%. Simultaneously, the remaining oil in the stimulated reservoirs remained high. Therefore, multi-stage fractured horizontal wells should increase fracturing clusters to form fracture network for improving production.

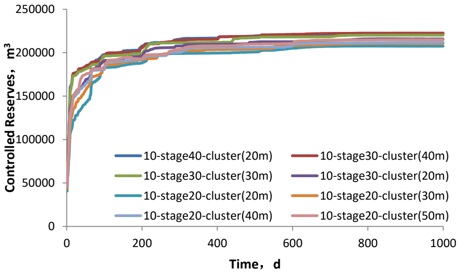


Figure 3: Change in controlled reserves of different clusters with time

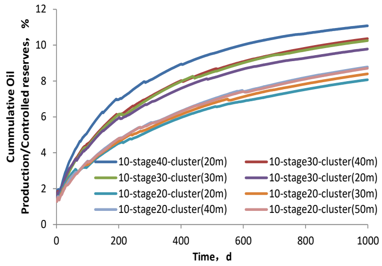
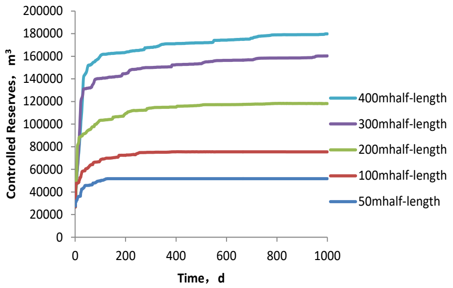


Figure 4: Change in recovery degree of different clusters with time

3.3 Influence of different fracture lengths on controlled reserves

Figure 5 shows the changing curve of the drainage scope reserves of hydraulic fractures with lengths of 50, 100, 200, and 300 m over time in ten stages, four clusters, and 1,000 m horizontal wells. As fracture length increased, the drainage scope reserves rose with fracture numbers, but this trend slowed down. Changes in fracture length in tight oil reservoirs had a significant effect on drainage reserves. As the fracture length increased, the stimulated reservoir area grew, which was conducive to the spread of pressure. Figure 6 shows the ratio of the cumulative oil production to the controlled reserves at different times and fracture lengths. As the fracture length rose, the drainage scope reserves eventually increased. However, when the fracture length was 50 and 100 m, the ratio of the cumulative oil production to the controlled reserves increased rapidly to a steady state. At a fracture length above 200 m, the ratio of the cumulative oil production to the controlled reserves in the steady-state period increased.



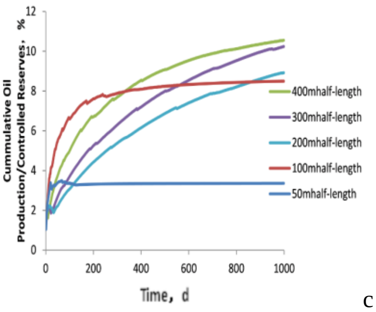
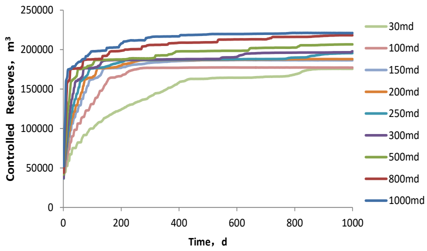


Figure 5: Change in controlled reserves of different half-lengths with time

Figure 6: Change in recovery degree of different half-lengths with time

3.4 Influence of micro-fractures permeability on controlled reserves



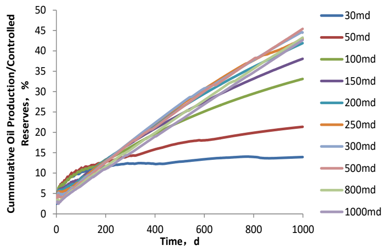


Figure 7: Change in reserves of different microfractures permeability with time

Figure 8: Change in recovery degree of different microfractures permeability with time

The permeability of the micro-fractures of the dual porosity model was set to 30, 50, 100, 150, 200, 250, 300, 500, 800, and 1,000 md. Figure 7 shows the changing curve of the drainage scope reserves of micro-fractures permeability with time in ten stages, four clusters, and 1,000 m horizontal wells. Under the same SRV and when the permeability of micro-fractures differed, the controlled reserves increased with the increase in permeability. When the permeability of micro-fractures was less than 100 md, the drainage scope reserves increased rapidly and the growing rate slowed down. As shown in Figure 8, the ratio of the cumulative oil production to the controlled reserves quickly reached a steady state at 30md and 50md of micro-fractures, and the rest of micro-fractures permeability curve still rose. The ratio of the cumulative oil production to the controlled reserves rate rose to 45% as the permeability increased, and cumulative oil production still increased. Therefore, in the process of volume fracturing treatment, the permeability of micro-fractures increased, and the drainage scope reserves produced in the stimulated reservoir gradually grew.

4. Conclusion

Numerical simulation revealed the research results of the drainage area and drainage scope reserves of multi-stage fractured horizontal wells in different well types as follows:

1. Outside of the stimulated reservoir volume, the reservoir permeability was low, seepage resistance was high, the external reservoir was used in a small range, and the horizontal well of 10 stages 40 clusters had a final drainage scope of less than 60.61%.
2. Compared with the fracture clusters, the fracture stages exerted a greater influence on the range of horizontal wells in volume fracturing treatment. The greater the stages are, the larger the range of drainage area will be. Therefore, the fracture stages should be increased compared with the fracture clusters.
3. Changes in fracture length in tight reservoirs significantly influenced the drainage scope. For the tight reservoir permeability of less than 1 md, the reservoir threshold pressure gradient increased sharply and the external reservoir in the SRV area was difficult to use without fracturing. Therefore, as the fracture length increased, both the SRV area and drainage scope widened.
4. Under the same stimulated reservoir volume, when micro-fractures permeability differed, the SRV area could be used internally, but the external reservoir increased with the increase in permeability.

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