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Steady-state optimization model and practical design of the fracture network system in tight sand gas reservoirs

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ABSTRACT

Based on steady-state seepage theory in porous media and the Galerkin method, a finite element model of seepage field in a stimulated reservoir volume of a horizontal well was established. The relationship between fracture conductivity and production under different fractured drainage volumes was studied. For shale gas reservoir, the productivity will increase as the fractured drainage volume enlarges. However for tight sand gas reservoir, this study revealed that the fractured drainage volume should be maintained in the mid-small scale ($0.1 \leq \mathrm{FCI} \leq 0.25$) with highly conductive main fractures. For certain fracture network morphology, there exists a critical value or optimal value of SRV curve. The production increase slows down when SRV exceeds its critical value. Cluster spacing and number of clusters for horizontal well fracturing can be determined by critical value of SRV and FCI value. The paper studied the operational conditions for the creation of small and medium-scale fracture network. Firstly, analytical solution of pressure inside the fracture is derived from fracture dynamics of rocks. Pump rate of fracturing fluid, viscosity, rock dynamic fracture toughness, elastic modulus, Poisson's ratio, in-situ stress, natural fracture parameters are input parameters to this analytical solution. Optimized pump rate for small to medium-scale fracture network was derived from the dynamic expanding condition of fracture network.

1. Introduction

The idea of improving hydraulic fracture conductivity and length through inducing bi-wings fracture and inhibiting complex fractures in conventional reservoirs cannot be applied in tight sand reservoirs. Because the matrix conductivity of tight sand is very low and natural fractures are the main flow channel in tight sand reservoirs. Connecting and reactivating natural fractures by inducing hydraulic fractures can significantly improve the level of topological complexity of fracture network and the Stimulated Reservoir Volume (SRV) are also increased remarkably at the same time.

Recently some investigators used micro-seismic technology to study complex fracture propagation; dynamic propagation of hydraulic fracture front can be captured by micro-seismic events and the extension and complexity of hydraulic fractures can be reflected by the micro-seismic cloud (fracture mapping). Most fracture propagate in the form of network structure and the spatial extension of micro-seismic events increases with increasing of injected fluid in tight sand reservoirs and other naturally fissured reservoirs (Maxwell et al., 2002; Fisher et al., 2002). For this complex fracture propagation mode, the concept of SRV is proposed, and field studies have shown production grows proportionally with SRV when SRV is small. However, production increase slows down as SRV further increases (Mayerhofer et al., 2006, 2010). Olson and Taleghani (2009) studied the influencing factors on fracture network propagation, such as net pressure in fracture, angle between hydraulic fracture and natural fracture, and the difference between minimum and maximum horizontal stresses. They concluded that large fracture net pressure, large angle between hydraulic and natural fractures and small horizontal stress difference are conducive the generation of complex fracture network. Wu et al. (2011), (2012) concluded that the critical technologies to create complex fracture network are multi-stage multi-cluster perforation and low viscosity fracturing fluid, multi-stage fracturing, large pumping rate and massive amount of fracturing fluid can facilitate the creation of effective SRV. The brittleness is a critical rock characteristic that is conducive to effective stimulation. The key to stimulate less brittle formation is to optimize cluster spacing. Multiple stage fracturing conduces to changing in-situ stress field and triggering fracture reorientation,

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and then helps to distribute proppant evenly to sustain larger fracture surface. Basquet et al. (2003) developed a software to simulate the transient and pseudo-steady state flows of a slightly compressible fluid in Discrete Fracture Network (DFN) models. By taking into account the high fluid compressibility and the non-Darcian effects near the well bore, they extend the methodology to gas cases. Their result showed that the fracture heterogeneity distribution has a strong impact on SRV and therefore production (especially in the near-well region). Ding et al. (2014) discussed a mathematical model and a numerical approach for simulating the production of unconventional gas reservoirs. Specifically, they considered the flow behavior in a stimulated reservoir volume including a tight matrix and multi-scale fracture networks, namely primary hydraulic fractures, induced secondary fractures and micro-fractures. Fracture network was assumed to be orthogonal, and various physics related to unconventional gas reservoirs, such as adsorption/desorption, Klinkenberg and geomechanical effects, were quantified.

The design methods and software of multi-stage fracturing practice for tight sand gas reservoir are usually modeled from conventional bi-wing fracturing or design experience of large-scale fracturing for shale gas, a distinctive fracturing design and approach for stimulating tight sand gas reservoir is lacking (Zhao et al., 2013). In this paper, finite element model of fracture network of SRV for horizontal wells and its seepage field were established based on seepage theory in porous media and the Galerkin method to study relationship between fracture network conductivity and production under different fracture network scales, to analyze fracture network scale and type compatible with tight sand gas reservoir, and to optimize SRV, cluster spacing and number of clusters by production-SRV relation. The relationship between fracture network scale and various influencing factors such as pump rate, in-situ stress, size, inclination and azimuth of natural fracture were analyzed, and methods of calculating optimum pump rate to form expected fracture network were proposed.

2. Pattern and scale of fracture network

Spatial fracture network is a unique form of fractures formed using massive fracturing in tight reservoirs; scale and complexity of fracture network can be measured by Fracture Complexity Index (FCI). FCI is the ratio of the SRV width and length, Table 1 shows the scale range of fracture FCI (Guo et al., 2014).

The experience of successful exploiting tight sand gas with multistage massive fracturing of horizontal wells have proven that fracture network is a suitable stimulative fracture pattern to exploit tight sand reservoirs (Mu et al., 2014). However the suitable fracture network scale needs to be optimized for tight sand reservoir stimulation, also there exist uncertainty regarding to whether it is necessary to create primary fractures with high conductivity in tight sand reservoir. In view of the above problems, a finite element model of fracture network around a horizontal well and its seepage field were established, and then the effects of different patterns of fracture network (with or without primary fractures) and different fracture network scale on the production and recovery were simulated. Suitable patterns and scale of fracture network for tight sand gas reservoirs were also analyzed.

Table 1
The relationship of fracture network scale and FCI.

FCI	0–0.1	0.1–0.25	0.25–0.5	0.5–1
Fracture network scale	Small	Mid-	Mid+	Large

2.1. The finite element model of fracture network around horizontal well and its seepage field

In this paper, we study on fracture matrix optimization and formation. So in order to reduce computation difficulty and focus on the key problem, we compare the steady-state productions. Assuming vertical and horizontal permeability of formation are equal, according to Darcy's law, Eq. (1) shows the relationship of flow velocity, permeability and pressure drop.

$$v = -\frac{K}{\mu}\frac{dp}{dx} \tag{1}$$

For the three-dimensional steady flow, Eq. (2) is the mathematical model of the seepage field.

$$\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2} + \frac{\partial^2 p}{\partial z^2} = 0 \tag{2}$$

For the three-dimensional eight-node elements, the pressure at any point in the element can be calculated by the nodal pressure as shown by Eq. (3).

$$p = \sum_{i=1}^{8} N_i \cdot p_i \tag{3}$$

In which $N_i = \frac{1}{8}(1 + X_i \cdot \mathrm{l})(1 + Y_i \cdot \mathrm{m})(1 + Z_i \cdot \mathrm{n})$

To transform the three-dimensional seepage equation using the Galerkin method, integral equation is obtained by multiplying or weighting the residual by shape function N_i, as shown in Eq. (4).

$$\iiint_\Omega N_i K\left(\frac{\partial^2 p}{\partial x^2} + \frac{\partial^2 p}{\partial y^2} + \frac{\partial^2 p}{\partial z^2}\right)\mathrm{d}x\mathrm{d}y\mathrm{d}z = 0 \tag{4}$$

The permeability coefficient matrix can be obtained by substituting Eqs. (1) and (3) into Eq. (4).

$$K_{ij} = \iiint_\Omega K\left(\frac{\partial N_i}{\partial x}\frac{\partial N_j}{\partial x} + \frac{\partial N_i}{\partial y}\frac{\partial N_j}{\partial y} + \frac{\partial N_i}{\partial z}\frac{\partial N_j}{\partial z}\right)\mathrm{d}x\mathrm{d}y\mathrm{d}z \tag{5}$$

Three-dimensional steady-state flow boundary conditions is controlled by bottom hole pressure and formation pressure. The nodal pressure can be calculated from Eq. (6) assuming load matrix is F. Matrix F is generated by the pressure boundary condition.

$$Kp = F \tag{6}$$

The pressure value can be calculated at any point from the nodal pressure obtained, and then elemental influx can be calculated by Eq. (7).

$$Q = -\iint K\left[\frac{\partial p}{\partial x}\cos(\varphi, x) + \frac{\partial p}{\partial y}\cos(\varphi, y) + \frac{\partial p}{\partial z}\cos(\varphi, z)\right]ds \tag{7}$$

where v is the average velocity, cm/s; K is matrix or fracture permeability; μ is fluid viscosity, mPa,s; p is pressure within an element,10^{-1} MPa; N_i is the shape function; $_{pi}$ is nodal pressure, 10^{-1} MPa; X, Y, Z are the coordinate value in x, y, z-direction, cm; l, m, n are element length, width and height, cm; $\boldsymbol{K_{ij}}$ is element permeability coefficient matrix; $\boldsymbol{K}$ is overall flow matrix; $\boldsymbol{F}$ is load matrix; $\boldsymbol{p}$ is nodal pressure column vector; Q is element influx or flow rate, cm^3/s; φ is outward normal vector of cross section.

The fracture system is assumed to be orthogonal. Because the SOLID70 element type of ANSYS is capable of simulating nonlinear steady-state flow in porous media and temperature field, it can be used as seepage field (Zhang and Sun, 2013). The finite element model of fracture network seepage field can be built by SOLID70 element of ANSYS thermal analysis module. Considering that subsurface natural fracture distribution is irregular, in order to simulate flow smoothly, orthogonal fractures which are parallel