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Sensitivity analysis of hydraulic fracture geometry in shale gas reservoirs

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ABSTRACT

The combination of horizontal drilling and multiple hydraulic fracturing has been widely used to stimulate shale gas reservoirs for economical gas production. Numerical simulation is a useful tool to optimize fracture half-length and spacing in a multistage fracturing design. We developed a methodology to use a commercial reservoir simulator to simulate production performance of shale gas reservoirs after fracturing. We verified our simulation method with the available field data from the Barnett Shale. In this work, we performed a sensitivity study of gas production for a shale gas well with different geometries of multiple transverse hydraulic fractures, in which fractures′ half-lengths vary. Hydraulic fractures are divided into two outer and inner fracture groups. The simulation results revealed that the outer fractures contribute more to gas production when fracture spacing is small due to the effect of fracture interference. Also, we studied the effects of fracture half-length and fracture spacing on gas production. This work can provide some insights into characterization of hydraulic fracture geometry on the basis of production data in shale gas reservoirs.

1. Introduction

Newly developed techniques in the fields of horizontal drilling and hydraulic fracturing have made possible the current flourishing gas production from shale gas plays in the United States, as well as the fast-growing investment in shale gas exploration and development worldwide. Hydraulic fracturing has been used in the oil and gas industry since the 1940s. Multiple transverse hydraulic fractures in a horizontal wellbore can create a large stimulated reservoir volume (SRV), which is the main contributor to high gas production from shale gas plays with extremely low permeability (Javadpour et al., 2007; Warpinski et al., 2009; Javadpour, 2009; Soliman and Kabir, 2012).

Although hydraulic fractures improve gas production from shale gas wells, hydraulic fracturing is expensive. Long laterals require greater volume of liquids and proppants, contributing to higher cost (Kaiser, 2012). Therefore, optimization of hydraulic fracture parameters, such as fracture spacing and fracture half-length, is important. It is well known that the longer the fracture half-length and the shorter the fracture spacing, the higher gas production will be. The greater the number of fractures in the shale around the wellbore, the faster the gas will be produced (Kalantari-Dahaghi, 2011). In some cases, more than 20 fracture stages have been tried in a horizontal well in order to increase fracture contact with the formation and to produce high initial gas rates (Castaneda et al., 2010; King, 2010). Meyer et al. (2010) suggested that initial production increases linearly with number of fractures, but a high gas flow rate is not sustainable and will decline sharply once fractures interfere over a given lateral length. Fazelipour (2011) stated that more hydraulic fractures around the wellbore increase production rate; fractures are the key component to effective production. Mayerhofer et al. (2010) pointed out that a large SRV with small fracture spacing could provide maximum well performance and gas recovery, considering economic optimization in design. Waters et al. (2009) stated that optimum fracture spacing depends on the incremental cost associated with creating denser fracture systems or productivity improvement from available fracture networks. All of these studies suggest the importance of economic factors in optimizing multiple transverse hydraulic fractures. For example, reduction in fracture spacing is expensive and may even cause interference and subsequent reduction in gas production. Analytical models do not incorporate fracture interference and assume equal fracture half-length (Ambrose et al., 2011; Zhao et al., 2012); hence, numerical simulation is necessary.

In this paper, we performed a sensitivity study of gas production for a shale gas well with uncertain but possible hydraulic fracture geometry. Hydraulic fractures are divided into outer fractures and inner fractures (Fig. 1). The performance of the outer

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fractures is much more beneficial for gas production than is the performance of the inner fractures, owing to the interference effect of inner fractures. We also studied the effects of both fracture half-length and fracture spacing on gas production. The goal of this work is to provide insights into characterization of hydraulic fracture geometry on the basis of production data in shale gas reservoirs.

2. Shale gas reservoir modeling

Given the complex nature of hydraulic fracture growth and the very low permeability of matrix rock in shale gas reservoirs, coupled with the predominance of horizontal completions, reservoir simulation is a preferred approach to predict and evaluate well performance. Local grid refinement with logarithmic cell spacing is used in simulation to accurately model gas flow from the matrix to a fracture, i.e., properly incorporating the transient flow behavior from the matrix to and within the fracture. In a block, the hydraulic fracture is explicitly modeled; moreover, in order to properly simulate the large pressure drop between the matrix and the fracture, the matrix is described as some sub-cells whose size increases logarithmically while moving away from the hydraulic fracture. In addition, a dual-permeability grid is used to allow simultaneous matrix-to-matrix and fracture-to-fracture flow. This method can accurately and efficiently model transient gas production from hydraulic fractures of horizontal wells in shale gas plays (Rubin, 2010; Cipolla et al., 2010). The reservoir is assumed to be homogeneous and the fractures evenly spaced, with stress-independent porosity and permeability.

In our simulation, gas is flowing into the wellbore only through fractures, i.e., no matrix-wellbore communication exists. The gas flow, which is turbulent as a result of the high gas flow rate in hydraulic fractures, is modeled with non-Darcy flow. The

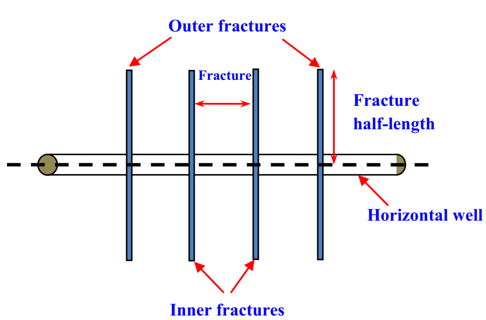

Fig. 1. Sketch of four induced hydraulic fractures in horizontal shale gas production well.

non-Darcy Beta factor used in the Forchheimer number is determined using a correlation proposed by Evans and Civan (1994):

$$\beta_{(f)} = 1.485E9/K^{1.021} \tag{1}$$

where the unit of K is md and the unit of β is ft^{-1}. The $\beta_{(f)}$ correlation was developed using more than 180 data points, including those for propped fractures, and was found to closely match the data (Rubin, 2010). Fig. 1 is a diagram of a typical shale gas completion design, illustrating several important geometric fracture parameters, such as fracture spacing and fracture half-length.

3. Case study

Published average reservoir data for the Barnett Shale in the Newark East field were used (Grieser et al., 2009). The Mississippian Barnett Shale, which sits on an angular unconformity above the Cambrian- to upper-Ordovician-age carbonates of the Ellenberger Group and Viola Formation and overlying the Pennsylvanian-age Marble Falls Limestone, is associated with the late Paleozoic Ouachita orogeny and located in the Fort Worth Basin area in North-Central Texas (Roy et al., 2013). The least principle stress is roughly NW to SE, which is the wellbore orientation, so that multiple transverse hydraulic fractures would be created (Fisher et al., 2004).

In this case, the well was stimulated by a four-stage fracturing with a single, perforated interval for each stage. Detailed reservoir information about this section of the Barnett Shale is listed in Table 1. For this well, fracture maps were obtained using geophones installed in offset wells, and estimates of fracture half-length at each initiation were provided (Grieser et al., 2009). We used the simulator CMG-IMEX (CMG, 2012) to model hydraulic fractures around the wellbore and simulate gas production, as illustrated in Fig. 2(a). Note the variation in fracture half-length in this well. History matching of the filed data is presented in Fig. 2(b). It shows a reasonable match between numerical simulation results and actual field gas flow data.

We set up another shale gas reservoir model with a volume of 990 ft × 1980 ft × 50 ft, based on average reservoir data from the Barnett Shale (Table 1). The effect of the number of hydraulic fractures on cumulative gas production with a base horizontal well length (660 ft) is presented in Fig. 3. It shows that cumulative gas production increases linearly at early times of production and then slows down at later times, finally reaching a plateau. The initial cumulative production increase is more dramatic in cases with a higher number of fractures (smaller fracture spacing). Fig. 4 shows the impact of the number of fractures on cumulative gas production from the base well (660 ft) after 10 years of production.

Table 1
Basic reservoir information.

Parameter	Barnett Shale case	Synthetic case	Unit
Model dimensions (L × W × H)	3500 × 5000 × 400 (1066.8 × 1524 × 121.9)	990 × 1980 × 50 (301.8 × 603.5 × 15.2)	ft (m)
Initial reservoir pressure	3800 (2.62 × 10^7)	3776 (3.60 × 10^7)	psi (Pa)
Bottom-hole pressure	1500 (1.03 × 10^7)	1000 (6.89 × 10^6)	psi (Pa)
Production period	3 (9.47 × 10^7)	10 (3.16 × 10^8)	year (s)
Reservoir temperature	180 (82)	180 (82)	°F (°C)
Gas viscosity	0.02 (0.00002)	0.02 (0.00002)	cP (Pa s)
Top of reservoir	7000 (2133.6)	6956 (2120.2)	ft (m)
Initial gas saturation	0.70	0.80	fraction
Compressibility of shale	3.0 × 10^{-6} (4.35 × 10^{-10})	10^{-6} (1.45 × 10^{-10})	psi^{-1} (Pa^{-1})
Fracture height	400 (121.9)	50 (15.2)	ft (m)
Fracture conductivity	9 (2.7 × 10^{-15})	100 (3 × 10^{-14})	md-ft (m^2-m)
Matrix permeability	0.00035 (3.5 × 10^{-19})	0.0001(9.9 × 10^{-20})	md (m^2)
Matrix porosity	0.04	0.08	fraction
Horizontal wellbore length	2052 (625.4)	600 (182.9)	ft (m)