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A simulation-based method to determine the coefficient of hyperbolic decline curve for tight oil production

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Abstract:
Tight oil reservoirs are characterized by the ultra-low porosity and permeability, making it a great challenge to enhance oil production. Owing to the fast development in hydraulic fracturing technology of horizontal wells, tight oil has been widely explored in North America. Individual wells have a long term of low production after a rapid production decline. This causes low cumulative production in tight oil reservoirs. A rate decline curve is the most common method to forecast their production rates. The forecast can provide useful information during decision making on future development of production wells. In this paper, a relationship is developed between the parameters of a hyperbolic decline curve and the reservoir/fracture properties when a reservoir simulation model is used based on the data from a real field. Understanding of this relationship improves the application of the hyperbolic decline curve and provides a useful reference to forecast production performance in a more convenient and efficient way.

1. Introduction

Tight oil resources have been widely developed in North America in the past decade (Li et al., 2019; Liu et al., 2019). Its production provides tremendous profits for industry and has a significant influence on energy economics (Zhang et al., 2019). Owing to the petro-physical characteristics of low porosity and permeability, a tight oil reservoir is difficult to be developed (Cipolla et al., 2010). How to better describe the production curve of tight oil is one of the challenges, which needs to be overcome in the reservoir engineering area.

To increase production, hydraulic fracturing is an efficient treatment for tight oil reservoirs. A horizontal well is used to make a contact area between a wellbore and a reservoir formation larger (Xu et al., 2018). After a well of this type is drilled, hydraulic fracturing is used to stimulate and increase the permeability around the wellbore (Xu et al., 2017). During a hydraulic fracturing process, a fluid is pumped into a reservoir generating new fractures under a high level of pressure. Oil can flow to a wellbore through new pathways created (Yang et al., 2019). Hydraulic fracturing exhibits good performance overcoming the issue of low permeability in tight oil reservoirs. Previously, many reservoir simulation studies have been done to research the production performance of tight oil. Zuloaga-Molero et al. (2016) did the simulation study on the CO_2-EOR (enhance oil recovery) in tight oil reservoirs considering complex fractures. Ghaderi et al. (2017) employed reservoir simulation to study the water and gas injection in tight oil field. Xu et al. (2018) applied the reservoir simulation in the study of embedded fracture model in tight oil development. Sun et al. (2019) performed the compositional reservoir simulation for CO_2 huff and puff in Bakken field. However, a simulation-based decline curve is still needed to serve the quick decision in the field. Many types of declines curves have been developed in the past, but the Arps decline curve will be focused in this study due to its simplicity and wide application (Arps, 1945; Sun, 2015).

This paper analyses the parameters of a hyperbolic decline curve based on reservoir simulation after a hydraulic fracturing process. The goal is to serve the production performance analysis and provide certain references for future exploitation and optimization of tight oil reservoirs.

2. Methodology

2.1 Reservoir properties

Numerical simulation is an effective approach to quantify reservoir performance and is widely used in unconventional

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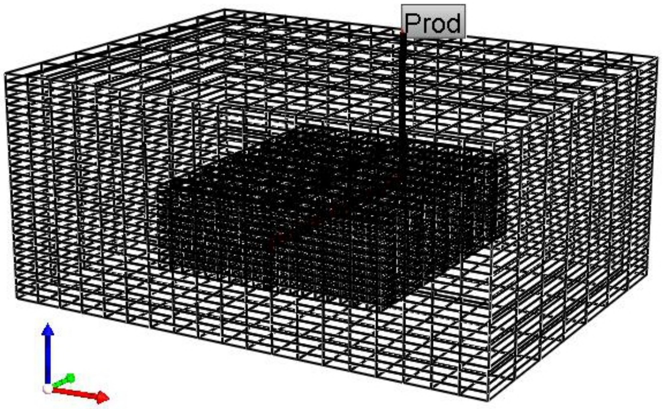

Fig. 1. Simulation model of horizontal well.

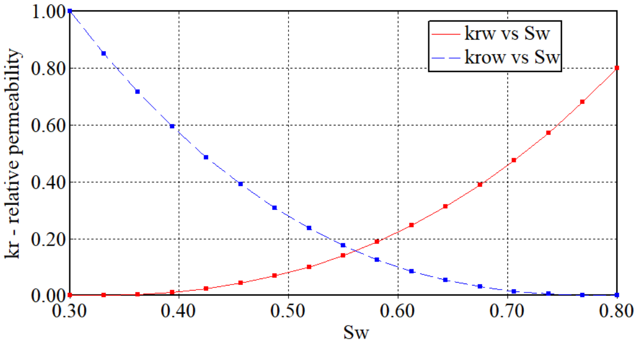

Fig. 2. Water-oil relative permeability curves.

reservoir development (Chen et al., 2006; Chen, 2007). It is a challenge to include tight oil reservoir properties during hydraulically fractured reservoir modeling processes for hydraulic fractures petroleum fluids and rock matrix (Lin et al., 2015). To accurately represent a real reservoir, the source of data for simulations must be reliable enough to capture its physical characteristics.

The geology of the formation under study is modeled using Computer Modelling Group's Geological Generalize Equation of State Model Reservoir Simulator software (Computer Modelling Group Ltd., 2017). GEM is a reservoir modeling software used to make exploration and production decisions. Based on field data, in this simulation model, 19 (I-direction) × 7 (J-direction) × 30 (K-direction) grid blocks are built with a grid size of 25 m in length (I-direction), 50 m in width (J-direction) and 1m in thickness (K-direction) as shown in Fig. 1. The properties of the tight oil reservoir are obtained from a real tight oil field found in Table 1 (Yu et al., 2017).

Relative permeability is a function of saturation in a reservoir, the ratio of effective permeability for a particular type of fluid to the absolute permeability. The absolute permeability is constant and independent of the fluid type in the reservoir. Effective permeability is the ability to preferentially transmit a particular fluid among other immiscible fluids in the reservoir and is typically lower than absolute permeability. Based on field data, Fig. 2 shows the water-oil relative permeability.

Table 1. Reservoir parameters.

Parameters	Values
Reservoir temperature (°C)	80
Reservoir compressibility (KPa^{-1})	10^{-7}
Permeability (md)	0.08645
Reference depth (m)	2,020
Reference pressure (MPa)	27
Water-oil contact (m)	3,000
Porosity	0.0821

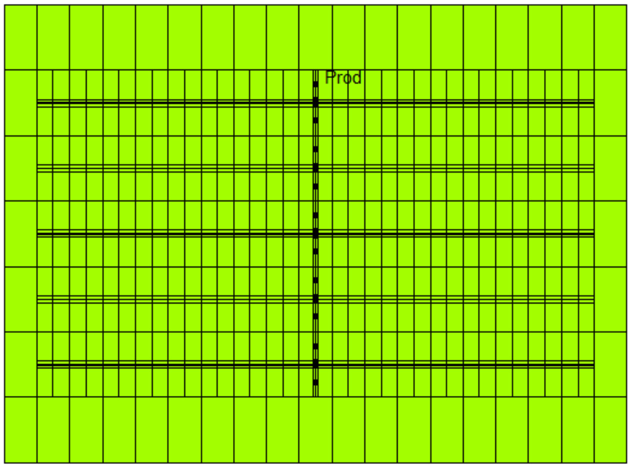

Fig. 3. Horizontal well with hydraulic fractures.

2.2 Hydraulic fracture properties

In this simulation model, a horizontal production well is placed in layer 20 and the bottom-hole pressure of the well is 10 MPa. This is lower than the average pressure of the area under study. Five parallel hydraulic fractures are placed along the length of the horizontal well (Fig. 3).

Hydraulic fracture conductivity is a parameter that measures the ability of hydraulic fractures to transmit hydrocarbon flow from a reservoir to a wellbore. It is controlled by a hydraulic fracture width and permeability. In the simulation process, the permeability of hydraulic fractures is difficult to analyse because of convergence issue and expensive computational costs. To solve this issue, grids with equal width and permeability are used to calculate the fracture permeability. The conductivity of a single hydraulic fracture is defined by the equation (Computer Modelling Group Ltd., 2017):

$$k_f \times w_f = k_e \times w_{block} \tag{1}$$

where k_f is the permeability of the fracture, mD; w_f is its width, m; k_e is its effective permeability, mD; w_{block} is the width of the grid representing the hydraulic fracture, m.

In Eq. (1), the hydraulic fracture permeability is a parameter that can be controlled by the engineer with a proppant

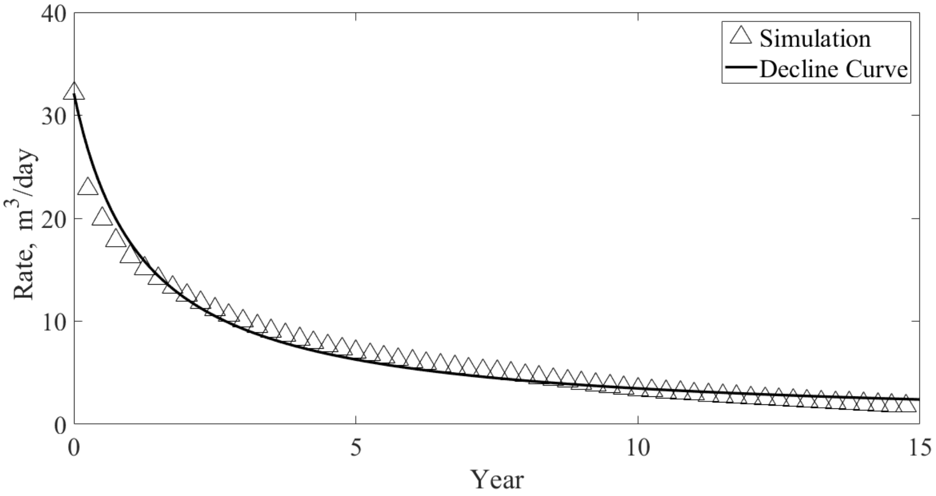

Fig. 4. Fitting result of production rate curves by simulation model and formula.

selection. There is a threshold for fracture conductivity. After this threshold, hydraulic fractures are infinitely conductive and the production performance does not change even when increasing the hydraulic fracture permeability. The engineer performs optimization studies for a variety of proppant types before choosing the best proppant type to include in a hydraulic fracture design (Lin et al., 2015).

The general properties of the hydraulic fractures are listed in Table 2.

2.3 Hyperbolic decline curve

A decline curve analysis is a graphical technique that aids engineers to estimate declining production rates and forecast future performance of oil and gas wells. It is applied when historical production has been reasonably established. A curve fitting is extrapolated to predict potential future performance. The decline curve analysis is vital to the oil industry, especially during acquisition and divestiture. It is useful for calculating discounted future financial plans and other relevant economic variables (Doublet et al., 1994).

For a decline curve equation, there are three types of models: exponential, harmonic and hyperbolic. The following equation is commonly used today as the basis for setting up decline curve analysis modelling (Arps, 1945):

$$\frac{1}{q}\frac{Dq}{Dt} = -bq^{d} \tag{2}$$

when $d = 0$, the equation yields an exponential decline model; when $d = 1$, the equation is said to be a harmonic model; when $0 < d < 1$, a hyperbolic model is defined. The graphs below compare different decline curve behaviors. Among the three types of decline curves, the hyperbolic decline is mostly applied to analyse the tight oil production performance. Wachtmeister et al. (2017) used the hyperbolic decline curve to do the study of tight oil wells in eagle ford shale. Yu et al. (2018) applied the hyperbolic decline method to study the production performance of tight oil wells in North America.

Table 2. General properties of models and hydraulic fractures.

Parameters	Values
Hydraulic fracture width (m)	0.001
Hydraulic fracture half-length (m)	200
Hydraulic fracture conductivity/ (md-m)	1000
Distance between hydraulic fractures (m)	50
Number of hydraulic fractures	5
Horizontal well length (m)	250
Minimum bottom hole pressure (KPa)	10000

Attanasi et al. (2019) used the hyperbolic decline curve to evaluate the Bakken oil wells. A hyperbolic decline curve equation is thus a good fit for application in tight oil reservoirs (Höök, 2009). The hyperbolic decline curve equation is as the following equation:

$$q(t) = \frac{q_i}{(1 + bD_i t)^{1/b}} \tag{3}$$

where q_i is an initial oil production rate (m^3/day); $q(t)$ is the oil production rate at time t (m^3/day); t is time (day); D_i is the decline rate, and b is an empirical parameter used in the hyperbolic equation ($0 < b < 1$).

In this hyperbolic decline curve equation, field data can provide the values for q_i and $q(t)$. The values of D_i and b are uncertain and should be analysed. The brief workflow to obtain the coefficients in this study is as follows: (1) perform the reservoir simulation and get the simulation-based decline curve; (2) employ the hyperbolic curve to match the production curve from reservoir simulation; (3) apply the coefficients from the step 2 into the decline curve in the field study. The main limitation of this workflow is that the coefficient is based on the match between decline curve and simulation, which

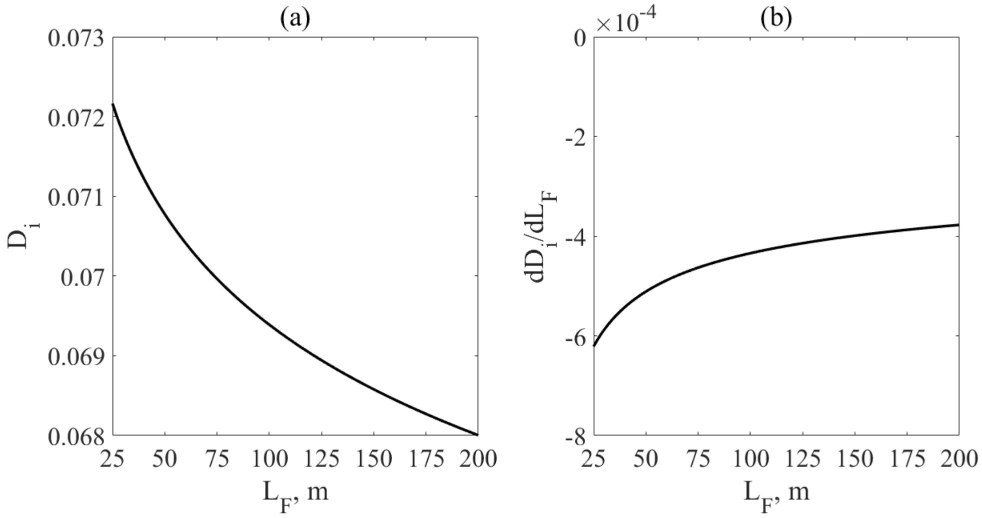

Fig. 5. (a) Relationship between fracture half-length (L_F) and D_i; (b) relationship between L_F and dD_i/dL_F.

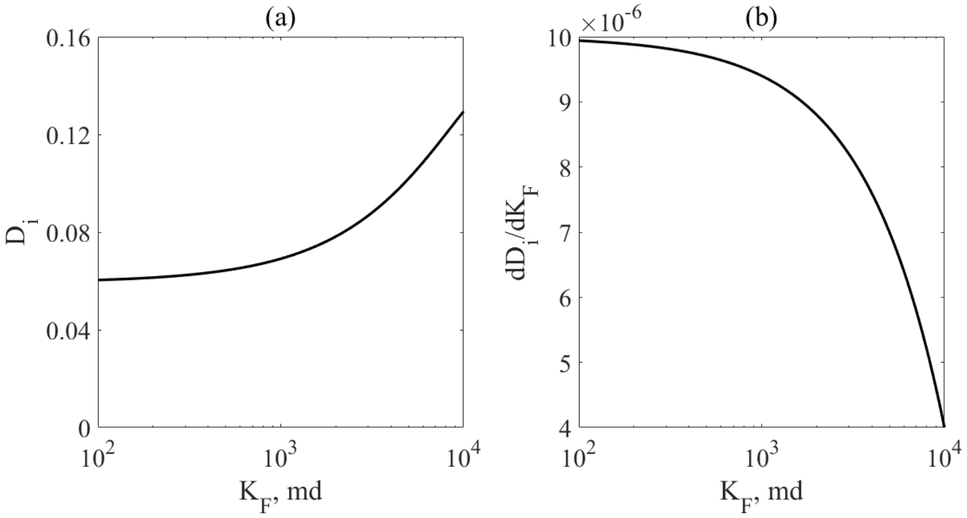

Fig. 6. (a) Relationship between fracture apparent permeability (K_F) and D_i; (b) relationship between K_F and dD_i/dK_F.

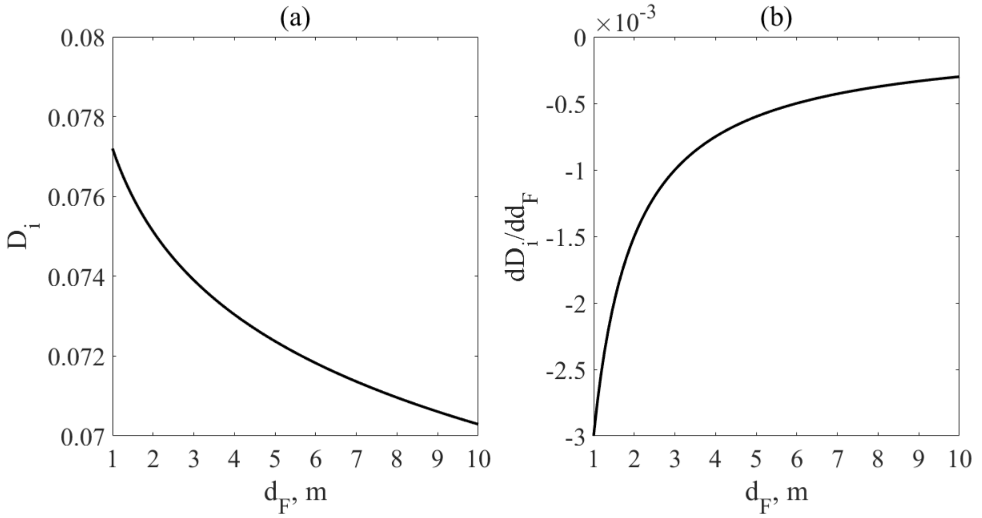

Fig. 7. (a) Relationship between vertical fracture length (d_F) and D_i; (b) relationship between d_F and dD_i/dd_F.

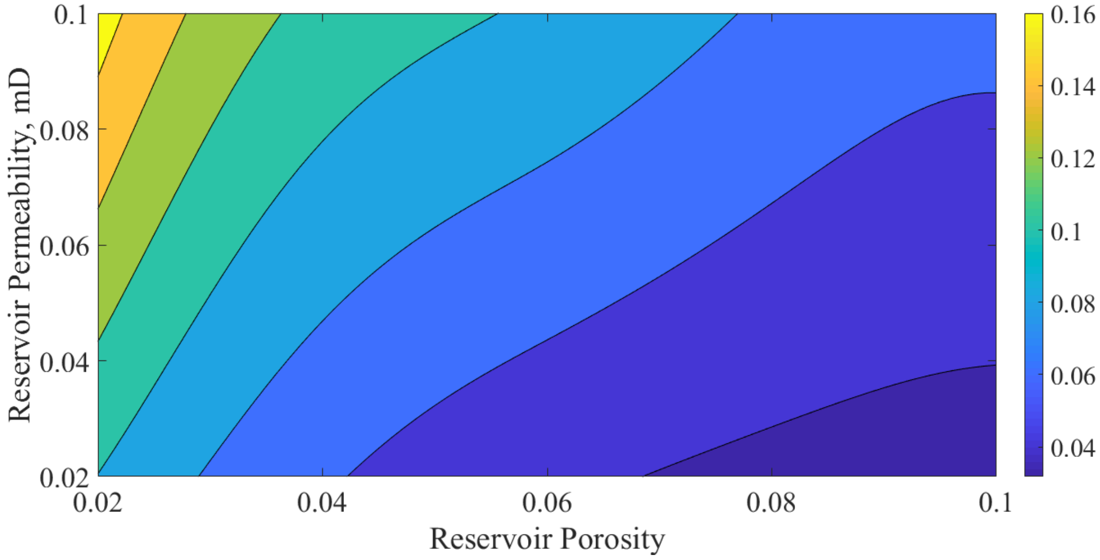

Fig. 8. Contour lines of D_i based on reservoir porosity and permeability.

indicates there is no strict derivation. However, this work will be improved in our future study.

3. Results and discussions

3.1 Simulation-based coefficients in hyperbolic decline curve

In Fig. 4, there are two curves shown. The solid curve represents the original production data from the simulation results and the points are the hyperbolic decline curve equation. As mentioned before, D_i and b are uncertain in the decline curve equation. By the process of fitting results of two types of production rate curves, the optimal values of D_i and b are determined. In this example, the value of D_i is 0.0685 and b is 0.999. The R^2 for this match is 0.9712, which indicates a great agreement between simulation data and decline curve. As shown in Fig. 4, there is still some difference in the early stage, which shows the limitation of hyperbolic decline curve to accurately describe the production performance of early stage.

3.2 Effects of hydraulic fracture properties on fitting curves

In this section, effects of hydraulic fracture properties on coefficients of hyperbolic decline curve are studied. Three key parameters selected are fracture half-length (L_F), fracture permeability (K_F), and fracture vertical length (d_F). D_i is focused on this part as b does not change significantly. Fig. 5(a) indicates the D_i decreases with the increase of L_F. For instance, the D_i equals to 0.0722 under the L_F of 25 m and 0.068 under the L_F of 200 m. Fig. 5(b) shows the decrease of D_i becomes slower with a higher fracture half-length; this is, the D_i is less sensitive to L_F in a horizontal well with a higher fracture half-length. The D_i increases with a higher fracture permeability as shown in Fig. 6(a), and the sensitivity of D_i to fracture permeability decreases with a higher conductivity in the hydraulic fracture indicated by Fig. 6(b). Fig. 7(a) further shows the D_i decreases with the increase of the vertical fracture length (d_F), and the D_i is less sensitive to the d_F with a larger d_F based on Fig. 7(b). Figs. 5-7 also indicate the D_i is most sensitive to vertical fracture length in this case. The result also indicate a longer fracture in both horizontal and vertical directions causes a lower D_i, and a higher conductivity leads to a higher D_i.

3.3 Effects of reservoir properties on fitting curves

In this section, effects of reservoir properties on fitting curves are discussed. As shown in Fig. 8, the contour line of D_i is plotted based on reservoir porosity and permeability, which provides the industry a fast estimation methods of D_i. For instance, the D_i equals to 0.0996 under the porosity of 0.02 and the permeability of 0.02 mD. With the increase of porosity and decrease of permeability, the D_i gradually decreases. For instance the D_i drops from 0.1696 to 0.0318 while the porosity increases from 0.02 to 0.1 and the permeability decreases from 0.1 to 0.02 mD. The pot of contour lines better assists in the quick determination of D_i in the field. D_i from different fields could also be combined with the type curve to serve the analog of hyperbolic decline curve.

4. Conclusions

In this paper a relationship between parameters from a rate decline prediction formula and fracture parameters is analysed and validated via simulation results. The main contribution of the study in this paper is to provide an insight into the effects of reservoir and fracture properties on a hyperbolic decline curve. The D_i increases when the fracture half-length and the vertical fracture length decrease, and the fracture permeability increases. The D_i is most sensitive to vertical fracture length in this study. With the increase of vertical fracture length, the sensitivity of D_i to vertical fracture length gradually decreases. With the decrease of porosity and increases of permeability, a higher D_i exhibits.

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