Supplementary energy development boundaries of staged fracturing horizontal wells in tight oil reservoirs

Lijun Lin¹, Wei Lin²,³, Shengchun Xiong³ and Zhengming Yang³

Abstract
Staged fracturing horizontal well technology is an important means of improving tight reservoir development efficiency. Taking a typical tight oil block in the Oilfield A as the studied area, the vertical well–horizontal well joint arrangement pattern is adopted in this study. The energy supplementary development effects of multiple permeability scales, different arrangement spacing, and different media (H₂O, CO₂) are discussed through the numerical simulation method. Combined with the principles of petroleum technology economics, the economic evaluation model for staged fracturing horizontal wells in tight oil reservoir development is proposed, thereby determining the technical boundary and economic boundary of supplementary energy development with different media. Studies indicate that the technical boundary and economic boundary of water-flooding development in the Oilfield A are 0.4 and 0.8 mD, respectively, and the technical boundary and economic boundary of CO₂-flooding development are 0.1 and 0.4 mD, respectively. This study provides theoretical support for field operation of Oilfield A and guidance for selection of development mode for tight oil reservoirs.

Keywords
Tight oil reservoir, staged fracturing horizontal well, H₂O and CO₂-flooding, technical boundary, economic boundary

¹School of Science, Shandong Jianzhu University, Jinan, China
²School of Engineering Science, University of Chinese Academy of Sciences, Beijing, China
³Department of Porous Flow and Fluid Mechanics, Research Institute of Petroleum Exploration and Development, PetroChina Company Limited, Langfang, China

Corresponding authors:
Wei Lin, University of the Chinese Academy of Sciences, 380 Huaihezhuang, Huairou District, Beijing 101407, China.
Email: linwei15@mails.ucas.edu.cn
Lijun Lin, Shandong Jianzhu University, Fengming Road, Lingang Development Zone, Jinan 250101, China.
Email: 14044@sdjzu.edu.cn

Creative Commons CC BY: This article is distributed under the terms of the Creative Commons Attribution 4.0 License (https://creativecommons.org/licenses/by/4.0/) which permits any use, reproduction and distribution of the work without further permission provided the original work is attributed as specified on the SAGE and Open Access pages (https://us.sagepub.com/en-us/nam/open-access-at-sage).
Introduction

Currently, tight oil is a relatively realistic substitute for the conventional hydrocarbon resources in the future. However, tight reservoirs are usually characterized by small pore throats, low permeability, large seepage resistance, and low single well production, and the effective development rates of the tight oil reservoirs are low (Lin et al., 2018, 2019; Shanley and Cluff, 2015; Wang et al., 2018). In order to improve the development efficiency, the staged fracturing horizontal well technology emerged (Moradidowlatabad and Jamiolahmady, 2018a, 2018b; Shen et al., 2018; Yu et al., 2017). The United States, Canada, and many other countries have initiated gas displacement production in their oilfields. The US oil production using CO2-flooding accounted for 23.6% of the oil production in enhanced oil recovery (Al-Mudhafar et al., 2018; Bayat et al., 2016; Hamidi et al., 2016; McCoy and Rubin, 2009). In the early 1960s, the small well spacing pilot tests were carried out in Daqing Oilfield, China, and four-point well pattern was adopted in the test area with the well spacing of 750 m. Compared with the water injection results of the control well group under the same conditions, the recovery rate was increased by about 10%. CO2-flooding tests were carried out under different gas injection pressures (Liu and Chen, 2010; Wang et al., 2014; Wang and Gu, 2012; Yuan et al., 2005). The rule of the impact of gas injection pressure on CO2-flooding gas channeling was studied. The impact of different gas injection modes on the effect of tight oil reservoir development was studied using the numerical simulation techniques. On water-flooding (Cai et al., 2010; Xie et al., 2015; Xu et al., 2014; Yang et al., 2013, 2010), factors affecting the effect of water-flooding, selection of water injection time, evaluation on the water-flooding effects in the test areas, and well pattern optimization and adjustment technologies were studied through means of physical simulation or numerical simulation.

Previous studies have shown that using CO2-flooding or water-flooding for tight oil reservoirs was feasible, but they only studied the factors affecting water-flooding or CO2-flooding and their development effects from the technical aspect. The research work to meet the technical requirements and economic feasibility has not yet been implemented (Kaiser, 2010; Kaiser and Yu, 2010; Wang et al., 2016).

Based on the aforementioned, this paper analyzes the effects of water-flooding and CO2-flooding development in staged fracturing horizontal wells for tight oil reservoirs with different permeability scales and different well spacing, calculates the 20-year production capacity, and then calculates the internal rate of return (IRR) using such development model combined with the methodology of economic evaluation for oil industry construction projects and thereby optimizes the development mode. This study provides theoretical supports for filed practice of studies and a good guidance for selection of tight oil reservoir development mode.

Geological settings

A typical block of tight oil reservoirs in Oilfield A is located in the north of China. Figure 1 is the geographic map of Oilfield A, which shows the specific location of studied area and the existing wells, and the color part is the oil region. Inner architecture of the studied area is simple compared with other reservoirs in China, and the main oil source area is almost horizontal. The reservoir is typical tight sandstone reservoirs with a
formation depth of 2234.4 m, formation pressure of 19.59 MPa, formation temperature of 100°C, saturation pressure of 6.02 MPa, and in situ oil viscosity of 1.84 mPa s. Figure 2 is the well location map of the studied area; the red line in Figure 2 represents a horizontal well and blue dots represent vertical wells.
Establishment of numerical models

The horizontal well–vertical well combined well pattern is adopted for oil development. The vertical wells are injection wells and the horizontal wells are production wells. Through field investigation and indoor physical simulation experiments, the parameters for numerical simulation are obtained and a numerical model is established. Figure 3 is a schematic diagram of a numerical model of a quarter injection and production unit.

The black line in Figure 3 represents a horizontal well and red lines represent induced fractures. The length of the horizontal well is 800 m. The number of stages for fracturing in horizontal wells after parameter optimization is 9. The half fracture length is 150 m. The half-length of fractures in vertical wells is 90 m. The non-isometric grid local infill method is adopted or fracture networks with a width of fractures of 1 m and flow conductivity of hydraulic fractures of 40 D cm. The scales of permeability of eight reservoirs are 0.1, 0.2, 0.3, 0.4, 0.6, 0.8, 1, and 5 mD, respectively. There are eight kinds of distances between the staged fracturing horizontal wells of different reservoirs and vertical well rows (hereinafter referred to as row spacing): 260, 280, 300, 320, 340, 360, 380, and 400 m. The increments along i direction corresponding to the eight kinds of row spacing are 530, 570, 610, 650, 690, 730, 770, and 810 m, respectively. The increment along j direction is 1010 m and k direction is 10 m.

Technical boundary determination

A numerical simulation approach is adopted to carry out parameter optimization and determine a reasonable working system. The 20-year recovery percent of reserves for each numerical model is calculated. Referring to the literatures (Xu et al., 2012; Yang et al., 2014) for the method of determining parameters of non-linear seepage flows with different permeability scales, the following basic principles shall be followed for the determination of the working system: (1) Injection speed is one of the main factors affecting productivity. When selecting a proper injection speed, the pressure in the gas injection well should not exceed 40 MPa as confined by the site operation conditions. (2) In order to ensure that the programs have comparability, the injection–production ratio of each program should be close or the same. (3) For reservoirs with the same permeability scale, the formation pressure variation during the production period should be maintained that the condition of formation pressure maintenance for small row spacing programs should be better than that for...
large row spacing programs. (4) When supplementing formation energy by injecting CO₂ and the produced gas–oil ratio is greater than some critical value, the injection well stops working and it indicates that channeling occurred.

Since the row spacing of the oil field is 400 m, we discuss the situation of 400 m here. When the row spacing is 400 m and the period of production is 20 years, natural depletion is adopted for reservoirs with different scales of permeability. The recovery percentages of reserves using water-flooding and CO₂-flooding development means are as shown in Figure 4.

It can be found from Figure 4 that:

1. When the permeability is 0.1 mD, the injection rate should not exceed 0.3 m³/day, or the pressure in the injection well will exceed 40 MPa within a short time, water injection will be difficult, the formation energy cannot be supplemented effectively, and the recovery percent of reserves will be low, which are caused by the characteristics of non-Darcy seepage flows and pressure sensibility. When the row spacing is reduced from 400 to 260 m and production period is 20 years, the recovery percent of reserves is only increased from 4.70 to 5.43%; comparing the recovery percent of reserves using water-flooding with that using natural depletion, its effect is weak and thereby considered as infeasible.

2. When permeability is 0.2 mD and the period of natural depletion is 20 years, the recovery percent of reserves is 4.77%. If water-flooding approach is adopted for 20 years’ production, the recovery percent of reserves will be 6.22%—an increase of 30.40%.

3. When permeability is 0.3 mD, natural depletion is adopted for 20 years’ production, the recovery percent of reserves is 5.15%. If water-flooding approach is adopted for 20 years’ production, the recovery percent of reserves will be 6.82%—an increase of 32.42%.

4. When permeability is 0.4 mD, the recovery percent of reserves of natural depletion is 5.43%. If water-flooding approach is adopted, the recovery percent of reserves will be
9.49%—an increase of 74.77%. Water-flooding in staged fracturing horizontal wells has major advantage comparing with natural depletion technically. In addition, the horizontal coordinate of the inflection point on the curve of recovery percent of reserves of water-flooding in Figure 4 is 0.4 mD. It is considered that under current conditions, the technical boundary of water-flooding in staged fracturing horizontal wells is 0.4 mD.

5. When permeability is 0.1 mD, the recovery percent of reserves of CO₂-flooding development is 6.24%, which is apparently higher than that of natural depletion development. According to the same research ideas, it is considered that the technical boundary of CO₂-flooding development in staged fracturing horizontal well is 0.1 mD.

**Economic boundary determination**

After calculating the parameter of productivity, we calculate the economic indicators combined with the principle of petroleum technology economics. IRR is selected as the main object of study in the paper. The economic signification of IRR is as follows: under such an interest rate, when the project is at the end of its life cycle, all the investment will be returned with the annual net income. The higher the IRR is, the larger the capability of fund return will be and the more fund will be returned with the same investment. Otherwise, the smaller the capability of fund return will be and the less the fund will be returned with the same investment. For a single program, the higher the IRR is, the better the economic benefit will be. The selected numerical model is solved by numerical simulation software, and the 20 years of production of each scheme is obtained. On the basis of previous studies, we established an economic optimization model for the development of staged fracturing horizontal wells, calculating the annual net present value (NPV), and then the IRR is calculated by using the relationship between NPV and IRR in engineering economics. In the actual calculation, we wrote Mini Programs in MATLAB, so we only need to import the income and cost parameters to calculate the IRR. According to the criteria of the petroleum industry currently published in China, the evaluation criterion of IRR is 12%. Therefore, if IRR < 12%, it is considered that the program is infeasible economically; if IRR ≥ 12%, it is considered that the program is feasible economically.

The basic data for calculating economic indicators are as follows: The cost of horizontal well drilling and fracturing is RMB 25 million/well. The cost of vertical well drilling is RMB 1621.20/m. Construction cost, logging cost, perforation cost, material cost, staff cost, maintenance and repair cost, and downhole operation cost are 900,000, 92,400, 219,800, 36,900, 20,600, 38,400, and 19,900 RMB/well, respectively. Expenditure on power and hydrocarbon handling cost are 21.11 and 14.75 RMB/t fluid, respectively. CO₂-flooding cost, H₂O-flooding cost, downhole operation cost, plant management cost, and other cost are 420.00, 260, 1.99, and 124.33 RMB/t respectively. Resources tax is RMB30/t. Construction tax, surtax for education expenses, sales tax, and value added tax are 3, 7, 3, and 17%, respectively.

**Establishment of the economic evaluation model**

An economic optimization model (1) for parameters of horizontal well hydraulic fractures is presented in the document, Horizontal well fracturing optimization design technology
The optimized fracture length is as shown in equation (2)

\[
NPV = \frac{R_n}{1+i} - \frac{COST_W - COST_T}{(1+i)^n} \tag{1}
\]

\[
NPV = \sum_{n=1}^{N} \frac{R_n}{(1+i)^n} - COST_W - N_f \cdot (COST_F + COST_{HH} + L_f COST_{LP}) \tag{2}
\]

where \(NPV\) is the net present value; \(R_n\) is the income of crude oil in \(n\) years (\(\times 10^4\) RMB); \(N\) is the total production time; \(COST_W\) is the cost of drilling (\(\times 10^4\) RMB); \(COST_T\) is the total cost of fracturing (\(\times 10^4\) RMB); \(COST_F\) is the cost including construction overhead, auxiliary equipment cost, cost of labor (\(\times 10^4\) RMB); \(COST_{HH}\) is the cost obtained with the number of fracturing pump vehicles multiplied by a single unit cost (\(\times 10^4\) RMB); \(COST_{LP}\) is the expenses on fracturing fluid and propping agent required for a unit fracture length (\(\times 10^4\) RMB); \(L_f\) is the fracture length (m); \(N_f\) is the number of fractures; \(i\) is the discount rate (%); and the current oil price is $50/barrel.

The value of equation (1) leaves out of consideration of the impact of row spacing, therefore, an amendment is made under the basis in this paper. There are four drilling investment estimate methods, namely investment indicator approximation method, historical cost method, engineering analogy method, and QUESTOR software method (Li, 2016; Zhong, 2018). The fourth method is adopted in this paper to break drilling investment cost into four parts: drilling construction cost, overhead of materials (including drilling fluid, brine, bits, cement, casing and tubing), design and project overhead cost \(COST_{IN}\) and unexpected expenses \(COST_{IM}\). Thereby, equation (3) is obtained

\[
COST_W = COST_M + COST_D + COST_{IN} + COST_{IM} \tag{3}
\]

where

\[
COST_M = L_{HW}COST_{HW} + L_{VW}COST_{VW} \tag{4}
\]

Substitute formula (4) into equation (3), then into equation (2) to obtain equation (5)

\[
NPV = \sum_{n=1}^{N} \frac{R_n}{(1+i)^n} - (L_{HW}COST_{HW} + L_{VW}COST_{VW} + COST_D + COST_{IN} + COST_{IM}) \cdot N_f - (COST_F + COST_{HH} + L_f COST_{LP}) \tag{5}
\]
Substitute $COST_D = COST_M \times 3\%$, $COST_IN = COST_M \times 1\%$ into equation (5) to obtain

$$NPV = \sum_{n=1}^{N} \frac{R_n}{(1+i)^n} - \left[ (L_{HW}COST_{HW} + L_{VW}COST_{VW}) \times 1.04 + COST_{IM} \right] - N_f \cdot (COST_F + COST_{HH} + L_fCOST_{LP})$$

(6)

If only the row spacing is changed, the economic optimization model of staged fracturing horizontal row spacing is as shown in equation (7)

$$NPV = \sum_{n=1}^{N} \frac{R_n}{(1+i)^n} - \left[ (L_{HW}COST_{HW} + L_{VW}COST_{VW}) \times 1.04 + COST_{IM} \right] - COST_T$$

(7)

When the row spacing has changed, to get the relationship between the NPV and row spacing, which is convenient for scheme comparison, the coefficient $\alpha$ is introduced

$$NPV_1 = \alpha \cdot \sum_{n=1}^{N} \frac{R_n}{(1+i)^n} - \left[ (\beta_1 \cdot L_{HW}COST_{HW} + \beta_2L_{VW}COST_{VW}) \times 1.04 + COST_{IM} \right] - \beta_1 \cdot COST_T$$

(8)

where $\alpha = V_1/V$ ($V_1$ is the model volume after row spacing reduced (m$^3$) and $V$ is the model volume before row spacing is reduced (m$^3$)).

**Study on the economic boundary of water-flooding**

Taking three permeability levels, 0.1, 0.6, and 0.8 mD, as representatives, the recovery percentages of reserves of water-flooding using different row spacing are as shown in Figure 5. The internal rates of return under different oil prices are as shown in Figure 6.
Figure 6. Row distances versus IRR of water-flooding. (a) 0.1 mD, (b) 0.6 mD, and (c) 0.8 mD. IRR: internal rate of return.
It indicates from Figure 5 that when the row spacing is reduced, the recovery percent of reserves is improved, indicating that water-flooding for supplementing energy using a small row spacing has a satisfactory effect. It indicates from Figure 6 that (1) under the same row spacing, the IRR is increased with the increment of permeability; (2) when the row spacing is reduced, the IRR has an apparent declining trend, which indicates that the income generated for increasing the recovery percent of reserves is smaller than the cost hereby generated; so, the IRR is reduced; (3) it can be found from Figure 6(a) that when the permeability is 0.1 mD, all the IRRs are <12%, indicating that if the vertical well-staged fracturing horizontal well combined well pattern is adopted for Oilfield A, using water-flooding for developing the 0.1 mD reservoirs is economically undesirable; (4) when the permeability is 0.6 mD, if price ≥$70.55/barrel, it is economically feasible; (5) when the permeability is 0.8 mD, if the price is ≥$59.38/barrel, it is economically feasible; (6) when the permeability is 1 mD, if the price is ≥$42.76/barrel, it is economically feasible. Therefore, under the current oil price, the economic boundary of water-flooding in Oilfield A is 0.8 mD.

**Study on the economic boundary of CO₂-flooding**

When the row spacing is 400 m, the internal rates of return using CO₂-flooding for development of different reservoirs are summed up in Figure 7. It indicates from Figure 7 that when the permeability is 0.1 mD, all the IRRs are <12%. Using CO₂-flooding for 0.1 mD reservoir development in staged fracturing horizontal wells in Oilfield A is economically undesirable. However, for reservoirs with a permeability greater than or equal to 0.4 mD, using CO₂-flooding for development in staged fracturing horizontal wells is economically desirable. Therefore, under the current oil price, the economic boundary of water-flooding in Oilfield A is 0.4 mD.

**Comparative analysis**

Figure 8 shows the curve of recovery percent of reserves when the row spacing is 400 m for different reservoirs. It indicates from the curve that (1) when the permeability ranges from 0.1 to 1.0 mD, the recovery percent of reserves increased with the increment of permeability, but the recovery percent of reserves with CO₂-flooding is higher than that of water-flooding;

![Figure 7. Permeability versus IRR of CO₂-flooding. IRR: internal rate of return.](image)
when the permeability increased to 4.5 mD, the recovery percent of reserves with water-flooding is higher than that of CO2-flooding for development.

Figure 9 shows the curve of IRR using a row spacing of 400 m for different reservoirs under the current oil price. It indicates from the curve that (1) the IRR increased with the increment of permeability; (2) when the permeability ranges from 0.1 to 1.0 mD, it is apparently more economically feasible using CO2-flooding for development than using water-flooding; (3) when the permeability increased to 3.5 mD, water-flooding is more economically feasible than CO2-flooding.

**Figure 8.** Permeability versus recovery percent of water and CO2-flooding.

**Figure 9.** IRR under the current oil price. IRR: internal rate of return.
In summary, when the permeability is greater than 0.1 and smaller than 0.4 mD, water-flooding is technically infeasible. It is recommended to adopt CO₂-flooding for development in Oilfield A; when the permeability is greater than 0.4 mD and smaller than 0.8 mD, both modes of development are technically feasible, but water-flooding is economically infeasible. Therefore, it is recommended to adopt CO₂-flooding for development in Oilfield A; when the permeability is greater than 0.8 mD and smaller than 3.5 mD, both development modes are technically and economically feasible, but the recovery percent of reserves of CO₂-flooding for development is higher than that of water-flooding, and CO₂-flooding for development is more economical. Therefore, it is recommended to adopt CO₂-flooding for development in Oilfield A; when the permeability is greater than 3.5 mD and smaller than 4.5 mD, the recovery percent of reserves of CO₂-flooding for development is still higher than that of water-flooding, but CO₂-flooding for development is not as economical as water-flooding. Therefore, the development mode should be selected according to its own demands in Oilfield A; when the permeability is greater than 4.5 mD, the recovery percent of reserves of water-flooding is higher than CO₂-flooding and the IRR is large, and it is recommended to adopt water-flooding in Oilfield A.

Conclusions

1. Under the current oil prices, for a typical block of tight oil reservoirs in Oilfield A, the technical boundary of water-flooding in staged fracturing horizontal wells is 0.4 mD and the economic boundary is 0.8 mD; the technical boundary of CO₂-flooding for development is 0.1 mD and the economic boundary is 0.4 mD;
2. When the permeability is greater than 0.1 and smaller than 3.5 mD, it is recommended to adopt CO₂-flooding for development in Oilfield A; when the permeability is greater than 4.5 mD, it is recommended to adopt water-flooding for development in Oilfield A; when the permeability is greater than 3.5 and smaller than 4.5 mD, it is recommended to select a development mode according to its own demands in Oilfield A; when the permeability is greater than 4.5 mD, it is recommended to adopt water-flooding for development in Oilfield A.

Acknowledgements

We are very grateful to the reviewers and editors for their valuable comments and suggestions.

Declaration of conflicting interests

The author(s) declared no potential conflicts of interest with respect to the research, authorship, and/or publication of this article.

Funding

The author(s) disclosed receipt of the following financial support for the research, authorship, and/or publication of this article: The work was funded by the Shandong Provincial Natural Science Foundation, China (ZR2018BA024) and the Project of Shandong Province Higher Educational Science and Technology Program (No. J17KB069).

ORCID iD

Wei Lin https://orcid.org/0000-0002-8643-594X
References
Al-Mudhafar WJ, Rao DN and Srinivasan S (2018) Robust optimization of cyclic CO2 flooding through the gas-assisted gravity drainage process under geological uncertainties. *Journal of Petroleum Science and Engineering* 166: 490–509.
Bayat M, Lashkarbolooki M, Hezave AZ, et al. (2016) Investigation of gas injection flooding performance as enhanced oil recovery method. *Journal of Natural Gas Science and Engineering* 29: 37–45.
Cai JC, Yu BM, Zou MQ, et al. (2010) Fractal analysis of invasion depth of extraneous fluids in porous media. *Chemical Engineering Science* 65(18): 5178–5186.
Hamidi H, Haddad AS, Mohammadian E, et al. (2016) Ultrasound-assisted CO2 flooding to improve oil recovery. *Ultrasónicos Sonoquímica* 35(Pt A): 243–250.
Jiao XQ (2001) A preliminary discussion on relationship between internal rate of return and capital structure for self-possessed fund. *Techno-Economics in Petrochemicals* 17(4): 59–62.
Kaiser MJ (2010) Economic limit of field production in Louisiana. *Energy* 35(8): 3399–3416.
Kaiser MJ and Yu YK (2010) Economic limit of field production in Texas. *Applied Energy* 87(10): 3235–3254.
Li Y (2016) Research on methods of investment estimation for tight oil’s development projects. Master Thesis, China University of Petroleum – Beijing, China.
Lin W, Li XZ, Yang ZM, et al. (2018) A new improved threshold segmentation method for scanning images of reservoir rocks considering pore fractal characteristics. *Fractals* 26(2): 1840003.
Lin W, Li XZ, Yang ZM, et al. (2019) Multiscale digital porous rock reconstruction using template matching. *Water Resources Research* 55(8): 6911–6922.
Liu QZ (2000) Application of rate of return indication to economic evaluation. *Journal of the University of Petroleum, China* 23(3): 103–104.
Liu YZ and Chen XL (2010) Miscible conditions of CO2 flooding technology used in low permeability reservoirs. *Petroleum Exploration & Development* 37(4): 466–470.
McCoy S and Rubin E (2009) The effect of high oil prices on EOR project economics. *Energy Procedia* 1(1): 4143–4150.
Moradidowlatabad M and Jamialahmady M (2018a) The performance evaluation and design optimisation of multiple fractured horizontal wells in tight reservoirs. *Journal of Natural Gas Science and Engineering* 49: 19–31.
Moradidowlatabad M and Jamialahmady M (2018b) New approach for predicting multiple fractured horizontal wells performance in tight reservoirs. *Journal of Petroleum Science and Engineering* 162: 233–243.
Shanley KW and Cluff RM (2015) The evolution of pore-scale fluid-saturation in low-permeability sandstone reservoirs. *AAPG Bulletin* 99 (10): 1957–1990.
Shen WJ, Li XZ, Lu XB, et al. (2018) Experimental study and isotherm models of water vapor adsorption in shale rocks. *Journal of Natural Gas Science and Engineering* 52: 484–491.
Wang H, Liao X, Zhao X, et al. (2014) The study of CO2 flooding of horizontal well with SRV in tight oil reservoir. In: *SPE energy resources conference*, Port of Spain, Trinidad and Tobago, 9–11 June 2014.
Wang JC, Xu JW, Wang YQ, et al. (2018) Productivity of hydraulically-fractured horizontal wells in tight oil reservoirs using a linear composite method. *Journal of Petroleum Science and Engineering* 164: 450–458.
Wang K, Feng LY, Wang JL, et al. (2016) An oil production forecast for China considering economic limits. *Energy* 113: 586–596.
Wang X and Gu Y (2012) Oil recovery and permeability reduction of a tight sandstone reservoir in immiscible and miscible CO2 flooding processes. *Industrial & Engineering Chemistry Research* 50(4): 2388–2399.
Wu Y and Zhao GJ (2005) Comparison between the net present value method and the internal rate of reform method. *Science Technology and Engineering* 5(18): 1294–1297.
Xie Q, Ma D, Wu J, et al. (2015) Potential evaluation of ion tuning waterflooding for a tight oil reservoir in Jiyuan Oilfield: Experiments and reservoir simulation results. In: SPE Asia Pacific enhanced oil recovery conference, Kuala Lumpur, Malaysia, 11–13 August 2010.

Xu QY, Jiang WW, Wang XW, et al. (2014) Optimization of fracturing parameters in well pattern with horizontal and vertical wells combined in super-low permeability oil reservoir. Special Oil & Gas Reservoirs 21(2): 111–114.

Xu QY, Yang ZM, He Y, et al. (2012) Numerical simulation and economical evaluation of nonlinear seepage in advance water-flooding block. Science Technology and Engineering 12(14): 3328–3329.

Yang P, Guo H and Yang D (2013) Determination of residual oil distribution during waterflooding in tight oil formations with NMR relaxometry measurements. Energy & Fuels 27(10): 5750–5756.

Yang ZM, Yu RZ, Su ZX, et al. (2010) Numerical simulation of the nonlinear flow in ultra-low permeability reservoirs. Petroleum Exploration and Development 37(1): 94–98.

Yang ZM, Zhang ZH, Liu XW, et al. (2014) Physical and numerical simulation of porous flow pattern in multi-stage fractured horizontal wells in low permeability/tight oil reservoirs. Acta Petrolei Sinica 35(1): 85–91.

Yu RZ, Bian YA, Qi YD, et al. (2017) Qualitative modeling of multi-stage fractured horizontal well productivity in shale gas reservoir. Energy Exploration & Exploitation 35(4): 516–527.

Yuan H, Johns RT, Egwuenu AM, et al. (2005) Improved MMP correlation for CO₂ floods using analytical theory. SPE Reservoir Evaluation & Engineering 8(5): 418–425.

Zhang J (2001) Comparative analysis of dynamic decision-making methods of investment project evaluation. Journal of China University of Mining & Technology 30(5): 70–73.

Zhong M (2018) The study on technical and economic evaluation of tight oil resources development. PhD Thesis, China University of Mining & Technology, China.