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Research Article

Evaluation of Reservoir Parameters and Well Productivity Based on Production Data: A Field Case in Xinjiang Oilfield, China

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The understanding of formation has always been a challenge for field development. In this paper, we evaluate the reservoir parameters and gas well productivity based on production data. The model of nonuniform conductivity of fractures in multistage fracturing horizontal wells (MFHW) is used to interpret the transient pressure data. Binomial and exponential deliverability equations and pressure dimensionless productivity formula are combined to evaluate the gas well productivity. After that, the key factors that influence gas well production are analyzed, and the gas rate vs. oil nozzle is presented. Results show that the fracture half-length and conductivity for high- and low-conductivity fractures, respectively, are obtained, apart from the reservoir pressure, permeability, skin factor, etc. The test time in each oil nozzle is recommended to extend to achieve stability and to obtain a more accurate absolute open flow potential. The findings of this study provides a guidance for the production data analysis of nonuniform conductivity of fractures in MFHW in the future work. And it can help for the better understanding of predicting gas production rates in MFHW.

1. Introduction

Rate and pressure are the most valuable data in the reservoir evaluation. No matter directly or indirectly, they are the inputs that needed in the all stages of production performance analysis [1–5]. Reservoir evaluation relies on amount of mathematical solutions of the flow equations for reservoir or well characterization, among which pressure transient analysis and well productivity evaluation are the most-often-used techniques in the petroleum engineering [6–9]. The main purpose of pressure transient analysis is to collect the shut-in pressure data under controlled well rate conditions to determine reservoir and fracture parameters and estimate reservoir size [10]. The productivity test is generally applied to evaluate the oil or gas well production capacity by changing the working system [11–14].

In a typical pressure transient analysis, pressure data is usually measured downhole (as close to the midreservoir as possible) while the flow rates are collected at surface. The pressure responses are generated by changing the production rates, and the pressure and its derivative data during a build-up (or falloff) period are analyzed to evaluate the reservoir features [15–18]. The pressure transient analysis starts during the 1950s and 1960s by Matthews and Russell [19]. In the early time, the pressure data is performed exclusively by hand with pencil and graph paper based on straight lines analysis [20, 21]. Starting in the late 1970s, more and more developments came from service companies. Type curve analysis was introduced by Bourdet and Gringarten [22], which marked the beginning of the end of manual analysis. Then, more complex models that consider different boundaries and reservoir types are proposed with the development of numerical techniques such as the Stehfest algorithm [23]. Since the introduction of pressure derivative curve proposed by Bourdet et al. [24, 25], pressure transient analysis has become a reliable tool and is accepted by researchers.

Derivatives have revolutionized pressure transient analysis by making it possible to identify different flow regimes from the slope of pressure and its derivative curves. After that, the power of pressure transient analysis is further enhanced with the introduction of deconvolution, which makes the analysis of variable-rate pressure data possible [26]. Gringarten et al. [27, 28] and Aluko et al. [29] described the pressure transient analysis is an inverse problem, which can be expressed as $I \rightarrow S \rightarrow O$, where the input "$I$" means the induced rate impulse; the output "O" is the measured pressure data, and the "S" represents the unknown reservoir system. To obtain the unknown reservoir system "S", we should identify the pressure responses by interpretation models [30–32].

Gas well production evaluation is the key of gas reservoir dynamic analysis ([33]; Wang et al. 2021). Unlike conventional production analysis for slightly compressible fluids, gas rate production considers two parts: (1) Forchheimier's flow equation, rather than Darcy's law, should be used to characterize the high-velocity flow of gas that flows in porous media [34]. Swift and Kiel [35] thought that the non-Darcy flow of gas flow results in an additional pressure drop near the wellbore. (2) Gas properties are highly pressure dependent, which leads to a highly nonlinear flow (Wang et al. 2021). From the 1920s to 1950s, some gas well production test methods, including back-pressure well test [36], isochronal well test [37], modified isochronal well test [38], and one-point method [39], were proposed, which were based on binomial methods for deliverability calculation. Binomial deliverability equation can better characterize the turbulent influence of gas flow, which is generally expressed as pressure, pressure-square, and pseudopressure method. With the binomial deliverability equation, the absolute open flow potential and the inflow performance relation curve can be obtained. Field engineers prefer to apply binomial pressure-square type to calculate gas well production. Chase and Alkandari [40] proposed a methodology to predict the gas productivity of fractured gas well by single-point test rather than the multipoint backpressure test. Wang et al. [41] presented a novel binomial equation that considers non-Darcy effects, and found that the non-Darcy effect affects high-permeability reservoirs more dramatically than the low-permeability reservoirs.

The model of nonuniform conductivity of fractures in MFHW is used to interpret the formation and fracture parameters with the transient pressure data, and it can obtain more accurate well test interpretation results. More importantly, the productivity evaluation is more in line with the actual situation of the formation. However, it requires higher quality of the build-up pressure data and production data.

2. Methodology

In this paper, we take a multifractured horizontal well in Xinjiang Oilfield as an example. Firstly, the pressure transient analysis method is described to interpret formation and fracture parameters. Secondly, the well productivity is evaluated by combining different approaches. Then, key influences factors on well production are analyzed, and finally the gas rate prediction in different working systems is presented. This work provides a clue to analyze the production data for exploratory wells. According to the main procedures, the general sketch of the problem under study and the workflow are presented in Figure 1.

3. Pressure Transient Analysis

Well SX161 is condensate gas well, located in Xinjiang Oilfield. It was subject to 11-stage fracturing, with a total fracturing fluid of $11992.80 \, m^3$ and a total proppant of $675.90 \, m^3$ from 6 August to 9 August 2021. It started to produce with natural energy from 15 August 2021. Then, the productivity well test was conducted with 5 oil nozzles: 5 mm, 6 mm, 7 mm, 8 mm, and 9.2 mm from 21 August to 3 September. After the productivity well test, it continued to produce by depletion from 4 September to 8 September. During 9 September to 18 September, this well was shut in to measure the build-up pressure. The pressure measurement history is presented in Figure 2.

The well is shut in to measure the build-up pressure data. The data points are smooth without any fluctuations by amplifying the well data, indicating the test data meets the analysis requirements. The pressure build-up speed is fast during the test period, with the pressure build up from 62.2 MPa to 66.61 MPa after 215.43 hours shut in. The pressure-derivative curve tends to a horizontal line after the wellbore-storage regime, which may be the vertical radial flow around the horizontal well. Then, the pressure and its derivative curves rise in parallel with 1/2 slope, indicating the linear flow regime that perpendicular to horizontal wellbore. Finally, there is a trend of horizontal radial flow at the end of the pressure-derivative curve.

The Saphir software (Kappa Workstation 5.20) is firstly applied to analyze the pressure response. The "Constant Wellbore + Horizontal fractured well + Homogeneous reservoir + Infinite boundary" model is selected to interpret the build-up pressure data. The pressure and its derivative matching curves are presented in Figure 3(a), and the interpretation results are shown in Table 1. Wellbore storage coefficient is $1.95 \, m^3/MPa$. Reservoir permeability is $0.586 \times 10^{-3} \, \mu m^2$. Fracture skin factor is 0.29. Fracture half-length is 20.56 m. Initial reservoir pressure is 68.91 MPa.

In the actual field gas well development, the proppants may not be uniformly distributed, which results in the nonuniform flux density and fracture conductivity along the fractures. Meanwhile, the fluid is not produced in every section of horizontal wells (Figure 4). Based on this phenomenon, Qin et al. [42, 43] proposed an approach to investigate the nonuniform fluid production along horizontal wellbore. The pressure drop is caused by hydraulic fractures and horizontal well. The pressure drops caused by n horizontal sections are presented by superposition while the pressure drops caused by hydraulic fractures are derived by the superposition of continuous-vertical-plane sources. This model can diagnose the high production location and production rate, and the high-conductivity fracture length near the horizontal well and the low-conductivity fracture length far from the
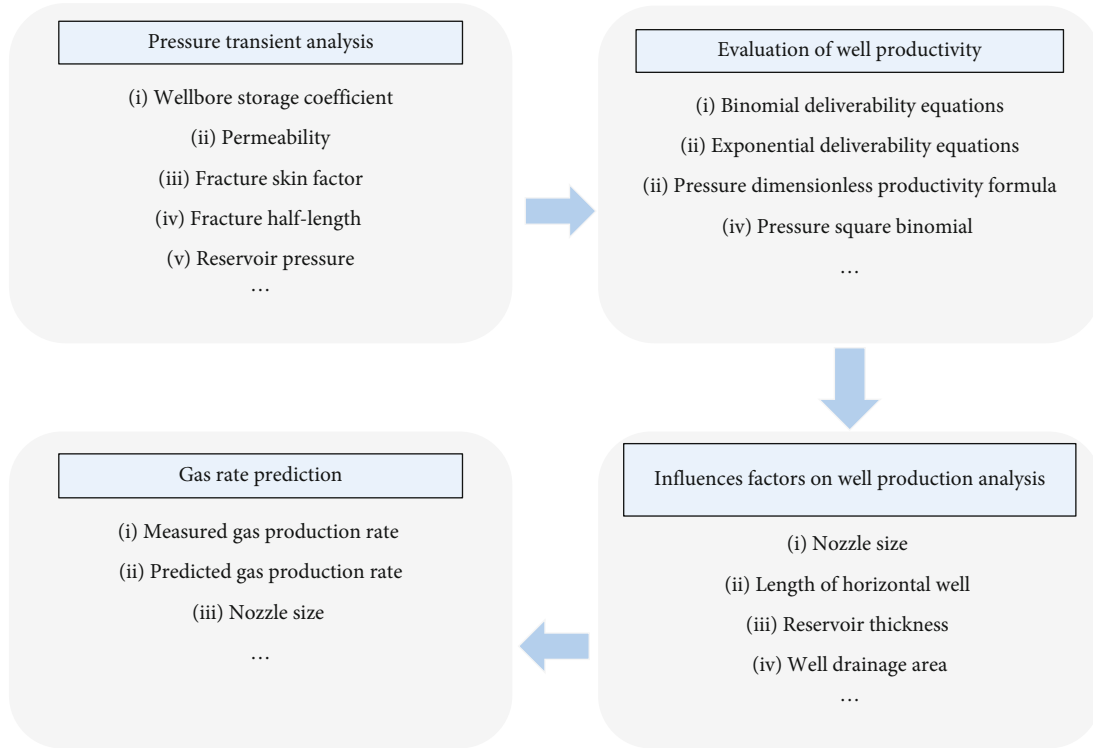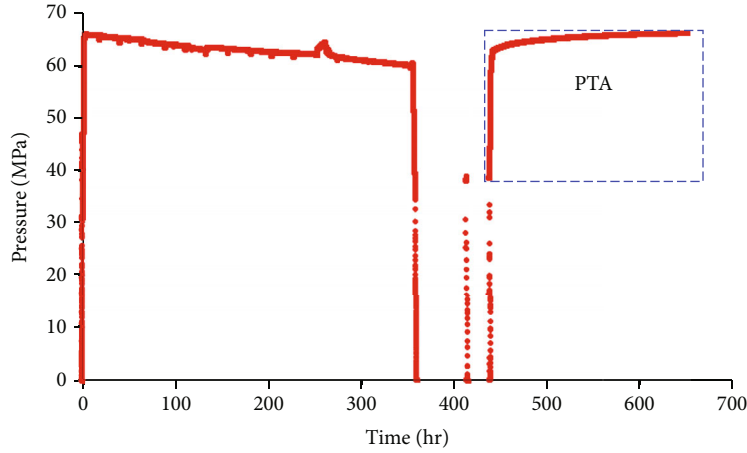
FIGURE 1: Workflow of the study.

FIGURE 2: Pressure history of Well SX161.

horizontal well. Using the model of Qin et al., the pressure and its derivative matching curves are presented in Figure 3(b), and the interpretation results are shown in Table 1. Wellbore storage coefficient is 1.27 m^3/MPa. Reservoir permeability is 0.672×10^{-3} μm^2. Fracture skin factor is 0.75. Initial reservoir pressure is 68.21 MPa. However, compared with conventional model in Saphir, the fracture half-length is 16.8 m high-conductivity fracture and 53.1 m low-conductivity fracture. These values are closer to the fracturing design parameters, and demonstrates that the fracturing effect does not meet the expectation.

4. Well Productivity Analysis

The procedure for the gas well productivity test is to conduct a series of flow tests in different (generally more than 4) flow rates and measure the stabilized bottom-hole pressure data under each flow rates. For gas wells, the flow rate and bottom-hole pressure should satisfy the following relation [44]

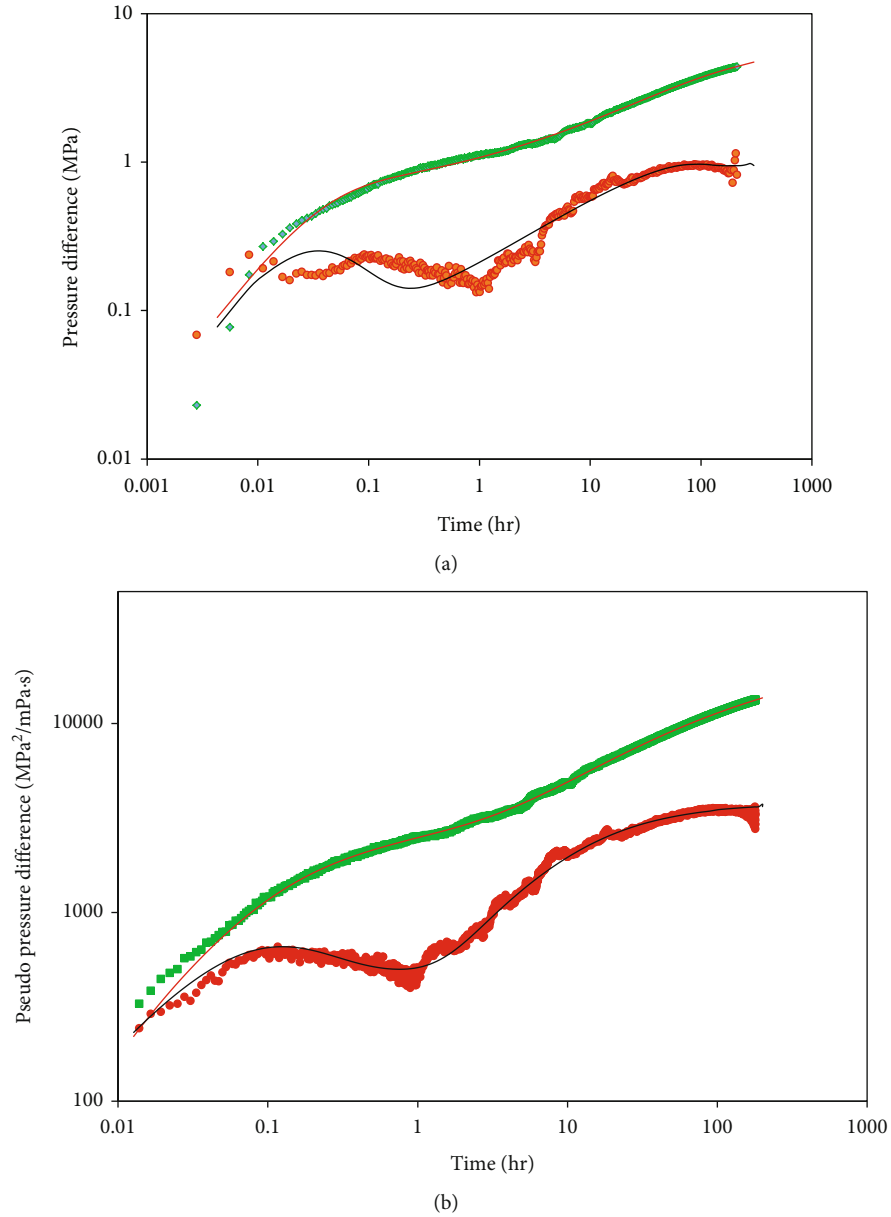$$p_R^2 - p_{wf}^2 = aq + bq^2, \tag{1}$$

(a)

(b)

FIGURE 3: Comparison of pressure matching by Saphir and the model of Qin et al.

TABLE 1: Interpretation results between commercial software and the model of Qin et al.

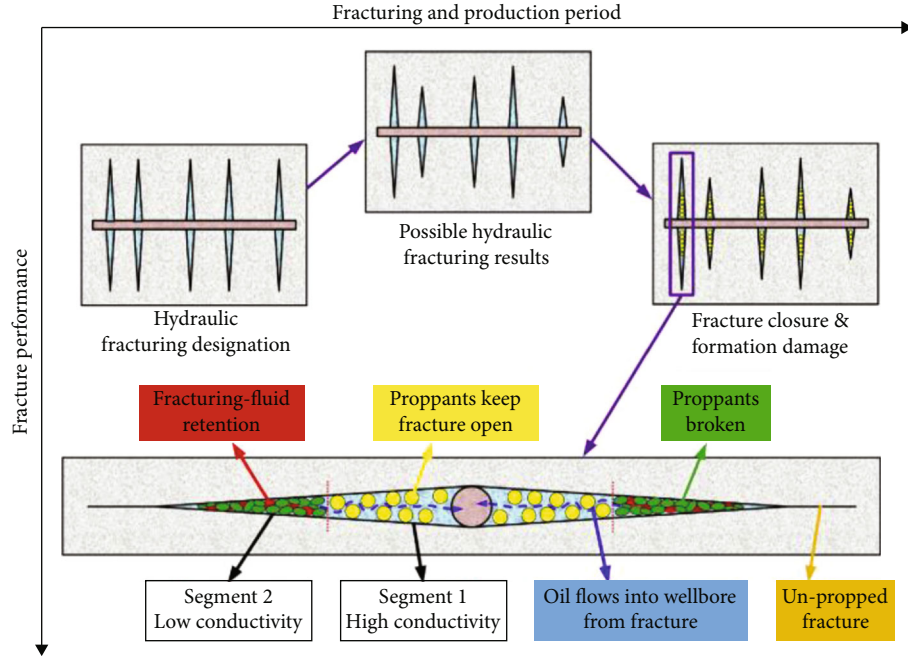|	Saphir	Model of Qin et al.
Model	Constant wellbore Horizontal fractured well Homogeneous reservoir Infinite boundary	Constant wellbore Double-segment fracture Homogeneous reservoir Infinite boundary
Wellbore storage coefficient (m³/MPa)	1.95	1.27
Permeability (10^{-3} μm^2)	0.586	0.672
Fracture skin factor	0.29	0.75
Fracture half-length (m)	20.56	16.8 + 53.1
Reservoir pressure (MPa)	68.91	68.21

FIGURE 4: Fracture performance during different period [42].

TABLE 2: Measured data of productivity well test.

Oil nozzles (mm)	Bottom-hole pressure(MPa)	Gas rate (10^4m^3/d)	Oil rate (m^3/d)	Qt rate (10^4m^3/d)
5	67.217	2.535	26.05	2.829
6	66.45	3.758	37.38	4.179
7	65.265	6.2975	55.61	6.924
8	64.06	8.6358	79.02	9.526
9.2	62.87	13.44	122.16	14.817

where p_R is the average reservoir pressure, MPa. p_{wf} is the bottom-hole pressure, MPa. q is the gas rate, 10^4m^3/d. a is the laminar flow coefficient for gas wells. b is the turbulence coefficient for gas wells.

From Equation (1), we can obviously find that a plot of $p_R^2 - p_{wf}^2/q$ vs q has a linear relation with the intercept of a and slope of b. The plot applies to both linear flow and radial flow. Upon the a and b obtained, we can easily derive the absolute open flow of gas well.

$$q_{AOF} = \frac{-b + \sqrt{b^2 + 4ap_R}}{2a},$$ (2)

where q_{AOF} is the absolute gas flow rate of the well, 10^4m^3/d.

The measured pressure and rate for the Well SX161 is shown in Table 2. The reservoir pressure and the bottom-hole pressures in different oil nozzles are greater than the dew point pressure (57.12 MPa), indicating that the fluid flows in single phase under formation conditions. Two fluid types are used in the productivity evaluation: one is oil and gas equivalent, and the other one is single gas. In the oil and gas equivalent, the oil rate is converted into gas when evaluating the well's productivity. Three methods are applied here; the deliverability equations and the absolute gas flow potentials are presented in Table 3. We find that different methods yield different results.

It should be noted that the exponential productivity is a semiempirical formula, which has a high possibility of deviation in the interpretation results and is just used for double-check purpose. The pressure dimensionless productivity method is an empirical formula that commonly used in the industry, which may not be suitable for the productivity evaluation of the well in this field. Since the flow pressures and production rates in every system are not stable, it is recommended to extend the test time of every system to achieve stability in the next productivity test, to obtain the accurate absolute open flow potential, understand the productivity of single well, and guide the production allocation in the future.

There are many factors influencing the well productivity of horizontal well, including reservoir thickness, well drainage area, horizontal length, and so on. Joshi [45] proposed an equation to calculate the oil productivity of horizontal wells.

TABLE 3: Gas well production results by different methods.

| Fluid type	Method	Equation	Absolute gas flow potential (10^4m^3/d)
Oil and gas equivalent	Pressure square binomial	$p_R^2 - p_{wf}^2 = 0.0001 \times q + 0.3878 \times q^2$	144.22
	Exponential	$q = 0.02 \times \left(p_R^2 - p_{wf}^2\right)^{0.9834}$	111.35
	Pressure dimensionless productivity	$q/q_{max} = 1 - 0.202\left(p_{wf}/p_R\right) - 0.798\left(p_{wf}/p_R\right)^2$	80.64
Gas	Pressure square binomial	Negative slope	/
	Exponential	$q = 0.0148 \times \left(p_R^2 - p_{wf}^2\right)^{1.0155}$	99.41
	Pressure dimensionless productivity	$q/q_{max} = 1 - 0.202\left(p_{wf}/p_R\right) - 0.798\left(p_{wf}/p_R\right)^2$	78.21
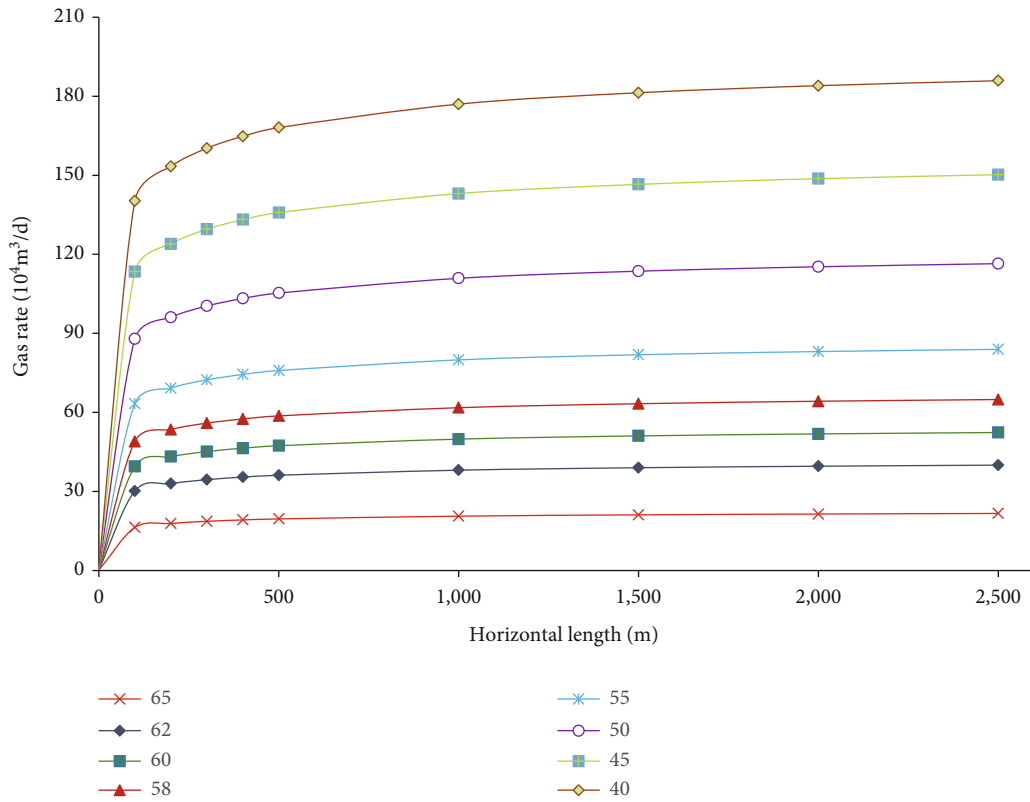
FIGURE 5: Relationship between gas rate and horizontal length in different bottom-hole-pressure.

$$q_g = \frac{kh\left(\psi_i - \psi_{wf}\right)}{1422T\left[\ln\left(r_{eh}/r_w'\right) - 0.75 + S\right]}, \quad (3)$$

where

$$r_{eh} = \sqrt{\frac{43560A}{\pi}}, \quad (4)$$

$$A = \frac{L(2b) + \pi y^2}{43560}, \quad (5)$$

$$r_w' = \frac{r_{eh}(L/2)}{x\left[1 + \sqrt{1 - (L/2x)^2}\right]\left[L/(2r_w)^{h/L}\right]}, \quad (6)$$

$$x = \left(\frac{L}{2}\right)\left[0.5 + \sqrt{0.25 + (2r_{eh}/L)^4}\right]^{0.5}. \quad (7)$$

q_g is the gas rate, 10^3ft^3/d. k is the permeability, $10^{-3} \mu\text{m}^2$. h is the fracture thickness, ft. ψ_i is the initial pseudopressure, psi^2/cp. ψ_{wf} is pseudo-bottom-hole-pressure, psi^2/cp. T is the reservoir temperature, R. S is the skin factor. r_{eh} is the drainage radius, ft. A is the drainage area, acre. L is the horizontal length, ft. x is the half of the major axis of the drainage ellipse,
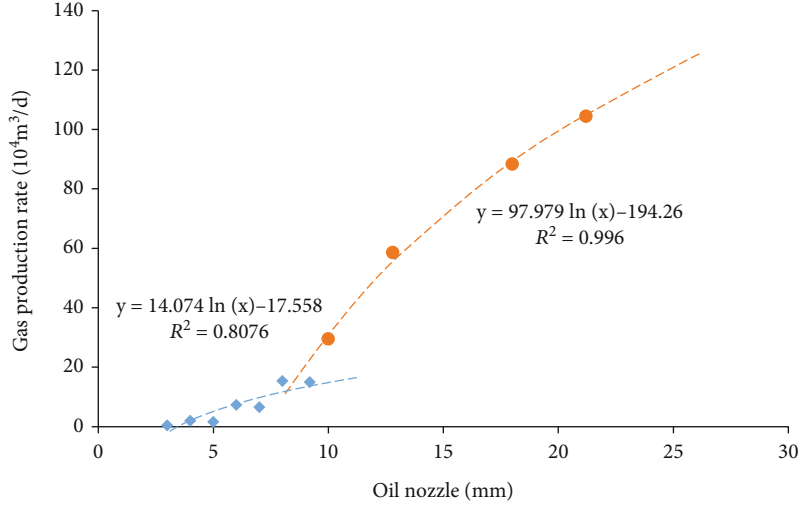
FIGURE 6: Correlation between gas well production rate and oil nozzle.

ft. y is the half the minor axis of the drainage ellipse, ft. r_w is the well radius, ft.

The horizontal section length of Well SX161 is 500 m. The half of the minor axis of the drainage ellipse is 100°m. Well radius is 0.06°m. Formation thickness is 17.16°m. Reservoir temperature is 126.8°C. Based on the interpretation result of pressure transient analysis, the skin factor is 0.99. The reservoir permeability is $5.641 \times 10^{-3} \circ \mu m^2$, and the reservoir pressure is 67.854°MPa. Applying Equations (3)–(7), we obtain the gas production rate with horizontal section length under different bottom-hole flow pressure conditions as shown in Figure 5.

We find that the gas production rate increases sharply with the increase of horizontal length firstly, then it turns to a slow upward trend. It reminds us that the oil increase rate decreases with the increase of horizontal length. The long horizontal section also adds the risk of water breakthrough and need more drilling cost. Therefore, it should balance the oil productivity and horizontal length. In addition, the gas production rate increases with the decrease of bottom-hole-pressure, as well acknowledged. Interestingly, the "inflection point", which signifies the turning point of oil well production increase rate, increases with the decrease of bottom-hole-pressure. Therefore, the long horizontal wells cannot give full play to its role of increasing production capacity under the pressure maintaining production condition. The horizontal length of Well SX161 is 500 m. If the oil field managers plan to amplify the pressure difference for the well production in the future, they are suggested to consider increasing the horizontal length, but no more than 1000 m as far as possible.

There are many methods to predict oil production, such as deliverability equations, rate transient analysis, empirical formula, nozzle size, and oil productivity regression. This well was tested twice for productivity, and the production rate grows greatly with the increase of oil nozzle. Therefore, it is necessary to know the production change rule and the key influence factors of the well, so as to facilitating the later

TABLE 4: Comparison between measured and predicted gas production rate.

Oil nozzle (mm)	Measured gas production rate ($10^4 m^3$/d)	Predicted gas production rate ($10^4 m^3$/d)
4	2.46	1.95
5	2.42	5.09
6	8.08	7.65
7	7.01	9.83
8	15.82	11.71
9.2	15.30	13.68
10	28.90	31.34
12.8	58.67	55.53
18	88.60	88.94
21.2	104.66	104.97
25	—	121.12
30	—	138.99
35	—	154.09

production allocation guidance. Through analyzing the relationship between gas production and the oil nozzle (Figure 6), we find that

$$y = \begin{cases} 14.074 \times \ln(x) - 17.558 & r < 7.8\text{mm}, \\ 97.979 \times \ln(x) - 194.26 & r \geq 7.8\text{mm}. \end{cases} \tag{8}$$

Table 4 presents the comparison between measured gas rate and the predicted gas rate that estimated by equation *, which shows a great consistency. Based on the regression rule, the predicted gas production rates with the oil nozzles of 25 mm, 30 mm, and 35 mm, are estimated. It should be noted that the gas rate cannot always increase with the increase of oil nozzle.

5. Summary and Conclusions

In this paper, we investigate the pressure behavior of multi-fractured horizontal well and evaluate the gas well productivity based on a field case in Xinjiang Oilfield, China. Several conclusions are derived as follows:

(i) The formation and fracture parameters can be interpreted through production data. The fracture half-length is 16.8 m high-conductivity fracture and 53.1 m low-conductivity fracture can be obtained by the model of Qin et al., which provides an approach to evaluate the fracturing effect.

(ii) The gas well productivity is evaluated combining different methods. It is recommended to extend the test time in each nozzle to achieve stability in the next productivity test and to obtain the accurate absolute open flow potential.

(iii) The key factors that influence gas well productivity are analyzed; the nozzle size is the most important factor, followed by the length of horizontal wells, and the relation of gas rate and oil nozzle is obtained.

(iv) The predicted gas production rates with the oil nozzles of 25 mm, 30 mm, and 35 mm are estimated as $121.12 \times 10^4 \mathrm{m^3/d}$, $138.99 \times 10^4 \mathrm{m^3/d}$, and $154.09 \times 10^4 \mathrm{m^3/d}$

Nomenclature

p_R: average reservoir pressure, MPa
p_{wf}: bottom-hole pressure, MPa
q: gas rate, $10^4 \mathrm{m^3/d}$
a: laminar flow coefficient for gas wells
b: turbulence coefficient for gas wells
q_{AOF}: absolute gas flow rate of the well, $10^4 \mathrm{m^3/d}$
q_g: gas rate, $10^4 \mathrm{m^3/d}$
k: reservoir permeability, $10^{-3} \mu\mathrm{m}^2$
h: fracture thickness, m
ψ_i: initial pseudo-pressure, $\mathrm{MPa^2/mPa \cdot s}$
ψ_{wf}: pseudo-bottom-hole pressure, $\mathrm{MPa^2/mPa \cdot s}$
T: reservoir temperature, R
S: skin factor
r_{eh}: drainage radius, m
A: drainage area, m^2
L: horizontal length, m
x: the half the major axis of the drainage ellipse, m
y: the half the minor axis of the drainage ellipse, m
r_w: well radius, m.

Data Availability

The data used to support the findings of this study are included within the article. The data used to support the findings of this study are available from the corresponding author upon request.

Conflicts of Interest

The authors declare no conflicts of interest.

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