Journal of Engg. Research **Vol. 3 No. (1) Mar 2015** pp. 149-171

تحديد العدد الامثل لحزم حفرة مفتوحة في الآبار الأفقية بواسطة نظام يسيطرة على تدفق لأنواع مختلفة من الخزانات

لوه وى، هايتاو لي، وانغ يونغ تشينغ، جنجو وانغ و مينجغون ينغ

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الخلاصــة

نظام تعبئة حفرة مفتوحة هو نظام مكتمل يتم نشرها كجزء من نظام صرف مستودعات التخليص الداخلي لإنتاج تدفق أكثر اتساقا. من وجهة نظر قابلية التشغيل والاقتصاد لنظام صرف مستودعات التخليص الداخلي، وعدد من حفرة مفتوحة يحتاج إلى أن يكون الأمثل من أجل تحقيق التكلفة الأكثر فعالية لأنواع مختلفة من الخزانات. وفي هذه الدراسة، تستخدم كل من النهج ثابت ومتغير مع الزمن لتقييم آثار انهاء مستودعات التخليص الداخلي مع تعبئة حفرة مفتوحة لتحقيق التدفق المتكافئ وتحسين الأداء. النهج ثابت توظف نموذج شبه تحليلي والتي تعتبر خزان غير متجانس وانخفاض الضغط في أنابيب، ومستودعات التخليص الداخلي. النهج المتغير مع الزمن توظف نموذج المتعددة المتقدم لمحاكاة المكامن. نتائج المحاكاة تشير إلى أن: أولا، الخزان المتجانسة ذات نفاذية عالية، هو الحل الانتهاء الأكثر فعالية من حيث التكلفة ولا يجب أن تستخدم نظام تعبئة حفرة مفتوحة في نظام الانتهاء مستودعات التخليص الداخلي. ثانيا، لخزان الرمال غير متجانسة، المحاكاة تحتاج إلى القيام بها من أجل العثور على العدد الأمثل من حفرة مفتوحة اعتمادا على درجة من التجانس المكمن. أخيرا، لخزان كربونات متكسرة، عدد الحفر المفتوحة يجب أن تكون بحد أقصى لضمان مشترك واحد فقط.

Optimization of the number of openhole packers in horizontal wells completed by inflow control devices for different types of reservoirs

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ABSTRACT

Openhole packers are completion hardwares that are deployed as a part of the ICDs completion system to produce a more uniform inflow profile. From the perspective of the operability and the economy of the ICDs completion system, the number of openhole packers needs to be optimized in order to achieve the most cost-effective completion solution for different types of reservoirs. In this study, both steady-state approach and transient-state approach are used to evaluate the effects of the ICDs completion with openhole packers on the inflow equalization and the well performance optimization. The steady-state approach employs a semianalytical model that considers reservoir heterogeneity and pressure drops in the annulus, tubing, and ICDs. The transient-state approach employs an advanced multisegment well model of the reservoir simulator Eclipse™. The simulation results indicate that: (i) For a high-permeability homogeneous reservoir, the most cost-effective completion solution should not use openhole packers in the ICDs completion system; (ii) For a heterogeneous sand reservoir, the simulation needs to be performed in order to find the optimum number of openhole packers depending on the degree of reservoir heterogeneity; (iii) For a fractured carbonate reservoir, the number of openhole packers needs to be maximized in order to guarantee that there is only one ICD joint per compartment.

Keywords: Different types of reservoirs; horizontal wells; inflow control devices; openhole packers.

NOMENCLATURE

L_i	Length of segment *i*
θ_i	Deviation angle of segment *i*
x_i, y_i, and z_i	Midpoint coordinates of segment *i*
Φ_e	Potential in the constant-pressure boundary
Φ_i	Potential at the midpoint of segment *i*
q_j	Inflow of segment *j*
h	Reservoir thickness
r_w	Wellbore radius
P_e	Pressure in the constant-pressure boundary
P_i	Pressure at the midpoint of segment *i*
ρ	Fluid density
g	Acceleration duo to gravity
μ	Fluid viscosity
k	Permeability of the reservoir
k_{ai}	Permeability of segment *i* in the altered zone
k^*	Constant background permeability
r_a	Radius of the altered permeability zone
s_{hi}	Skin of segment *i* caused by permeability heterogeneity
s_{di}	Skin of segment *i* caused by formation damage
k_{di}	Permeability of segment *i* in the damaged zone
a_{max}	Half-length of the horizontal axes of damaged zone at the heel
I_{ani}	Permeability anisotropic coefficient
S_i	Distance between the segment *i* and the toe of the horizontal well
L	Horizontal wellbore length
s_{ti}	Total skin of segment *i*
ΔP_{ani}	Pressure drop of segment *i* in the annulus
c_{ani}	Correction coefficient of friction factor of segment *i* in the annulus
f_{ani}	Friction factor of segment *i* in the annulus
Q_{ani}	Axial flow rate of segment *i* in the annulus
$D_{c,i}$	Wellbore diameter
$D_{t,o}$	Outside diameter of the tubing
ΔP_{ti}	Frictional pressure drop of segment *i* in the tubing
f_{ti}	Friction factor of segment *i* in the tubing
Q_{ti}	Axial flow rate of segment *i* in the tubing
$D_{t,i}$	Inside diameter of the tubing
ΔP_{ICD}	Pressure drop in ICDs

C_u	Unit conversion factor
Q_{ICD}	Flow rate through ICDs
d_{ICD}	Nozzle/orifice diameter of ICDs
C_d	Discharge coefficient for ICDs
ρ_{cal}	Density of the fluid used to calibrate ICDs
μ_{cal}	Viscosity of the fluid used to calibrate ICDs
a_{ICD}	Strength of helical ICDs

INTRODUCTION

In the past few decades, advances in drilling technologies have made it possible for horizontal and multilateral wells to become a primary design of reservoirs, especially in unconventional resources. The need for an efficient, economic and environmental friendly production has promoted the development of extended-reach horizontal and multilateral wells that enable larger well-reservoir contact. Increasing well-reservoir contact has many advantages in well productivity, drainage area, sweep efficiency, and delayed water or gas breakthrough. However, there are some new challenges associated with such long, possibly multilateral wells in completion and production (Saggaf, 2008). One of these challenges is imbalanced fluid inflow along the wellbore caused by frictional pressure drop of fluid flow and reservoir permeability heterogeneity along the wellbore. The uneven influx often leads to early water or gas breakthrough, which causes a reduction in oil recovery and uneven sweep of the drainage area.

The use of inflow control devices (ICDs) is an advanced well completion option that provides a practical means to minimize the problem (Alkhelaiwi & Davies, 2007; Li *et al*., 2011; Birchenko *et al.,* 2011). An ICD is a well completion device mounted on a joint of tubing or a sand-control screen to create a flow restriction in the fluid-flow path from the annulus into the inner conduit. Helical/labyrinthine channel, nozzle, orifice, and hybrid ICDs are provided by different suppliers (Ouyang, 2009). Even though the detailed structure varies from one design to another, the principle for different ICDs remains the same - restricting the flow by creating additional pressure drop and therefore adjusting the sandface pressure distribution to achieve a more uniform inflow profile along the horizontal wellbore. Extensive flow-loop testing and subsequent field work have been promising for ICDs to mitigate the imbalanced inflow and to optimize well and field performance (Henriksen *et al.,* 2006).

Typically, the ICDs completion system consists of three components, including: the linear hanger, openhole packers, and ICD joint containing ICD unit/module, debris barrier/sand control screen, and base pipe. For openhole packers, they are utilized to hydraulically isolate and compartmentalize multiple sections of the horizontal well with different characteristics in permeability, porosity, or fluid saturation. It was found that openhole packers for compartmentalization can offer potential benefits for the inflow equalization and the annulus flow control by analyzing a significant amount of actual production logs post-installation. The industry has gradually realized the importance of openhole parkers in the ICDs completion. Therefore, the use of these tools and the average number of openhole parkers per well have increased substantially in the past decade (Gavioli & Vicario, 2012). The standard compartment length has been reduced from the range of 500 to 1000 ft to the range of 75 to 100 ft. Furthermore, the new generation ICDs completion system decreases the compartment length down to individual joint size (38ft) by utilizing slide-on swelling-elastomer packers along the horizontal section (Hembling *et al*., 2007).

Although a smaller compartment length can be translated into a more optimum production strategy, the number of openhole packers that can be deployed in the horizontal well is limited by some factors such as the type of openhole packers to be used, the borehole conditions and undulations, the crew experience, and the incremental cost of the additional packers (Krinis *et al*., 2008). Meanwhile, the increase of openhole packers makes the completion tool string more complicated, which could result in a deviation of the system deployment at the target depth. Therefore, considering the operability and the economy of the ICDs completion system, the number of openhole packers needs to be optimized to achieve the most cost-effective completion solution for different types of reservoirs.

REVIEW OF OPENHOLE PACKER TYPES

There are several different types of openhole packers available in the industry with respective characteristics and application conditions, such as inflatable external casing packers, mechanical packers, swelling packers, constrictors, expandable packers, and reactive core packers (Alkhelaiwi & Davies, 2008). Usually, the selection of appropriate openhole packer for a specific application needs to consider the following factors: (1) requirements of construction technology; (2) downhole operation environment; (3) structure property of openhole packer; (4) surface and downhole matching equipment. The two most common openhole packers used in the ICDs completion are the mechanical packer type and the swelling packer type (Gavioli *et al.*, 2010), as shown in Figure 1.

The mechanical packers are non-inflatable openhole packers that simplify the installation operation process and create a positive annulus seal between the base pipe and the wellbore. Their composite material fabrication allows the elastomeric seal element to expand effectively in both round and irregularly shaped wellbores. The packers have been designed with mechanical, hydraulic pressure, or hydrostatic pressure setting mechanisms, allowing one-trip installation utilizing a shifting tool placed near the end of the inner workstring. Commonly, a seal containment system is essential to maintain the integrity of elastomeric seal element during the setting process and whenever subjected to a differential pressure. The disadvantages of the mechanical packers are limited differential pressure across the packer after setting and more expenditure compared with other openhole packers.

The swelling packers consist of a standard oilfield grade tubular with layered rubber elastomer bonded along the length of the tubular. The rubber elastomer swells in either oil or water to provide an effective annular seal between the base pipe and the wellbore. The oil swelling packers use the principle of absorption while the water swelling packers use the principle of osmosis. Due to the high elasticity of rubber, the size of swelling packers can be doubled, when they are in contact with hydrocarbons. The packers have no moving parts and require neither service tools nor surface operations to be activated or set, which reduces the risk of the well construction process and provide significant cost savings owing to reductions in rig time and materials. However, one disadvantage of swelling packers is that the sealing of the elastomer element is not immediate and it is a function of wellbore conditions and downhole fluid properties. Practically, the swelling packers need 5-100 days to complete the swelling process (Al-Yami, 2010).

In the oilfield practices, the swelling packers will be the first choice from the perspective of operation simplicity and cost saving. Notably, some operators prefer to running mechanical packers in order to address uncertain wellbore condition, immediate sealing need, and complete isolation of the high conductive fractured zones.

Fig. 1. Typical mechanical packer and swelling packer.

METHODOLOGY OF MODELING

Steady-state approach

To evaluate the inflow equalization effect of the ICDs completion with openhole packers for horizontal wells, a semianalytical model that couples the reservoir inflow to the downhole flow is developed (Valvatne *et al.*, 2003; Atkinson & Monmont, 2007). This model considers reservoir heterogeneity, varying damage along the wellbore because of drilling-fluid invasion into the formation, and pressure drops in the annulus, tubing, and ICDs.

Assumptions

The semianalytical model employs the following assumptions on the reservoir inflow and the downhole flow:

1. The horizontal well is in a slab reservoir with a no-flow boundary at the top and a constant-pressure boundary at the bottom (Figure 2).
2. Flow through the reservoir is steady-state and agreeable with the Darcy's law.
3. The horizontal well's length is much greater than the wellbore radius.
4. The downhole single-phase flow in the tubing, annulus, and ICDs is isothermal and steady-state. The fluid is incompressible, and its viscosity's dependence on pressure is neglected.

Note that the completion interval is not perfectly horizontal. True Vertical Depth (TVD) can vary along the wellbore since the semianalytical model is capable of taking into account the wellbore trajectory.

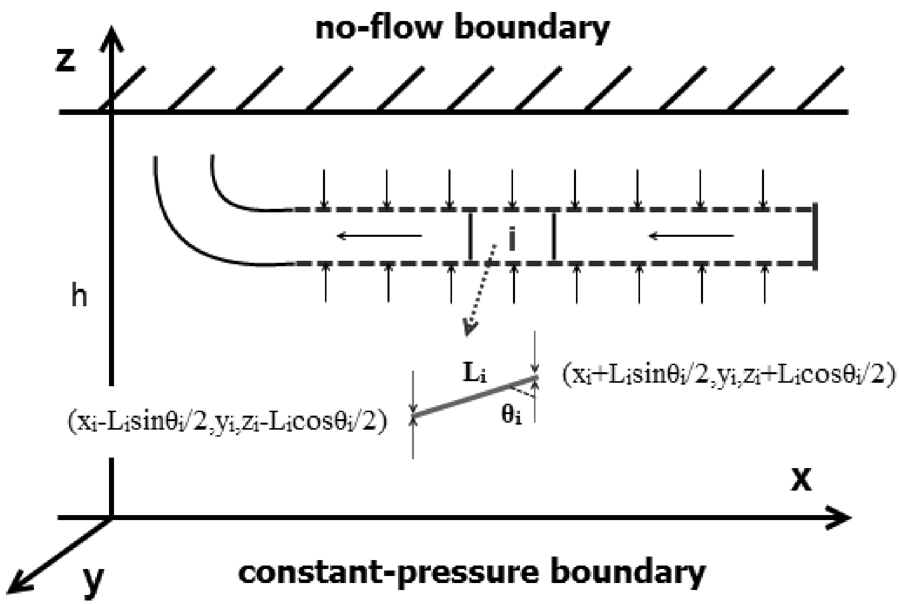

Fig. 2. Schematic of a horizontal well in a slab reservoir.

Modeling of reservoir inflow

The horizontal well is divided into N segments, and each segment is considered as a line sink with uniform inflow. The known parameters of segment i include the length L_i (m), the deviation angle θ_i (degree) and the midpoint coordinates (x_i, y_i, z_i) (m).

The image method is used to remove the impact of boundaries on well production (Gringarten & Ramey, 1973). According to the image method, the segment i in a slab reservoir with a no-flow boundary at the top and a constant-pressure boundary at the bottom can be turned into infinite production and injection segments alternately arranged in a unbounded space. The z-coordinates of production segments are $4nh+z_i$ and $4nh+2h-z_i$ ($n=0, \pm1, \pm2,\ldots, \pm\infty$), and the z-coordinates of injection segments are $4nh-z_i$ and $4nh-2h+z_i$ ($n=0, \pm1, \pm2,\ldots, \pm\infty$).

Using the potential theory and the principle of superposition, the potential drawdown at the midpoint of segment i is given by a linear combination of the contributions from all segments of the horizontal well:

$$\Phi_e - \Phi_i = \sum_{j=1}^{N} \frac{10^6 q_j \mu}{4\pi k L_j} \varphi_{i,j} \tag{1}$$

Where:

$$\varphi_{i,j} = \sum_{n=-\infty}^{+\infty} [\xi_{i,j}(4nh+z_j,0) + \xi_{i,j}(4nh+2h-z_j,1) - \xi_{i,j}(4nh-z_j,1) - \xi_{i,j}(4nh-2h+z_j,0)] \tag{2}$$

$$\xi_{i,j}(\eta_n,\varepsilon) = \ln \frac{r_{i,j1}(\eta_n,\varepsilon) + r_{i,j2}(\eta_n,\varepsilon) + L_j}{r_{i,j1}(\eta_n,\varepsilon) + r_{i,j2}(\eta_n,\varepsilon) - L_j} \tag{3}$$

$$r_{i,j1}(\eta_n,\varepsilon) = \sqrt{\left(x_i - x_{j1}\right)^2 + \left(y_i - y_{j1}\right)^2 + \left(z_i + r_w - \eta_{n1}(\eta_n,\varepsilon)\right)^2} \tag{4}$$

$$r_{i,j2}(\eta_n,\varepsilon) = \sqrt{\left(x_i - x_{j2}\right)^2 + \left(y_i - y_{j2}\right)^2 + \left(z_i + r_w - \eta_{n2}(\eta_n,\varepsilon)\right)^2} \tag{5}$$

$$(x_{j1}, y_{j1}, \eta_{n1}(\eta_n,\varepsilon)) = (x_j - L_j \sin\theta_j / 2, y_j, \eta_n - (-1)^{\varepsilon} L_j \cos\theta_j / 2) \tag{6}$$

$$(x_{j2}, y_{j2}, \eta_{n2}(\eta_n,\varepsilon)) = (x_j + L_j \sin\theta_j / 2, y_j, \eta_n + (-1)^{\varepsilon} L_j \cos\theta_j / 2) \tag{7}$$

According to the definition of potential function ($\Phi=P+\rho gz$), the pressure at the midpoint of segment i is given by:

$$P_i = P_e + 10^{-6} \rho g (z_e - z_i) - \sum_{j=1}^{N} \frac{10^6 q_j \mu}{4\pi k L_j} \varphi_{i,j} \tag{8}$$

Where, q_j is the inflow to segment j (m^3/s); h is the reservoir thickness (m); r_w is the wellbore radius (m); P_e is the pressure at the bottom boundary of the reservoir (MPa); ρ is the fluid density (kg/m^3); μ is the fluid viscosity (mPa·s); and k is the permeability of the reservoir (mD).

For modeling the reservoir heterogeneity, the s-k* approach proposed by Wolfsteiner *et al*. (2000) is used. The method models the permeability field in terms of a constant background permeability k* and an effective skin s that varies along the wellbore trajectory. The background permeability captures the global effect, while the skin captures the near-well effect. With reference to Hawkins' method, the effective near-well skin of segment i caused by the permeability heterogeneity can be expressed as:

$$s_{hi} = (\frac{k^*}{k_{ai}} - 1)\ln\frac{r_a}{r_w} \tag{9}$$

Where, k_{ai} is the permeability of segment i in the altered zone (mD) and r_a is the radius of the altered permeability zone (m).

Meanwhile, the elliptical-cone-shape model for damage distribution along the horizontal wellbore proposed by Frick & Economides (1993) is employed to compute the formation damage skin of segment i. This model predicts the maximum value of the formation damage skin at the heel and the minimum value at the toe:

$$s_{di} = \left(\frac{k_{ai}}{k_{di}} - 1\right)\ln\left(\left[\frac{2a_{\max}}{r_w\left[I_{ani}+1\right]} - 1\right]\frac{S_i}{L} + 1\right) \tag{10}$$

Where, k_{di} is the permeability of segment i in the damaged zone (mD); a_{max} is the half-length of the horizontal axes of damaged zone at the heel (m); I_{ani} is the permeability anisotropic coefficient; S_i is the distance between the segment i and the toe of the horizontal well (m); and L is the horizontal wellbore length (m).

Therefore, the total skin of segment i is then given by:

$$s_{ti} = s_{hi} + s_{di} \tag{11}$$

The total skin can be easily incorporated into the above reservoir inflow model in the form of the additional pressure drop. Therefore,

$$P_i = P_e + 10^{-6}\rho g(z_e - z_i) - \sum_{j=1}^{N}\frac{10^6 q_j \mu}{4\pi k L_j}\varphi_{i,j} - \frac{10^6 q_i \mu}{4\pi k L_i}s_{ti} \tag{12}$$

Modeling of downhole flow

As illustrated in Figure 3, the downhole flow of the ICDs completion with openhole packers is divided into two categories: (1) each ICD is separated by a openhole packer, so the flow direction in the annulus is definite; (2) multiple ICDs exist between two openhole packers and therefore the annulus flow direction is indefinite, because there is a flow diversion face between every two adjacent ICDs, which needs to be determined in the simulations. The two downhole flow types can be modeled with separate segments representing the annulus, tubing, and ICDs. First the reservoir inflow enters the annulus through the sandface, and then enters the tubing through ICDs.

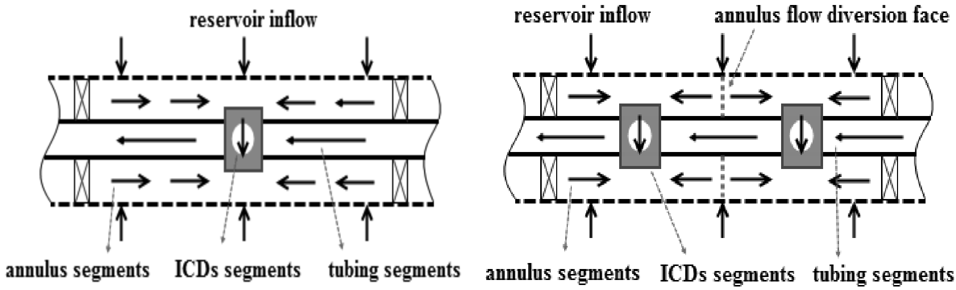

Fig. 3. Schematic of the downhole flow of the ICDs completion with openhole packers.

For the annulus flow, hydrostatic, frictional, and acceleration pressure drops should be taken into account because of the curved well trajectory and the reservoir inflow. These pressure drops can be calculated using the Ouyang wellbore-flow model (Ouyang *et al.,* 1998) with the concept of hydraulic radius as follows:

$$\Delta P_{ani} = 10^{-6}\rho g \sin(\theta_i - \frac{\pi}{2})L_i + \frac{2\times10^{-6} c_{ani} f_{ani} \rho L_i \left(2Q_{ani} - q_i\right)^2}{\pi^2 \left(D_{c,i}{}^2 - D_{t,o}{}^2\right)^2 \left(D_{c,i} - D_{t,o}\right)} + \frac{16\times10^{-6} \rho q_i \left(2Q_{ani} - q_i\right)}{\pi^2 \left(D_{c,i}{}^2 - D_{t,o}{}^2\right)^2} \quad (13)$$

where f_{ani} the friction factor of segment i in the annulus; c_{ani} is the correction coefficient of friction factor; Q_{ani} is the axial flow rate of segment i in the annulus (m^3/s); $D_{c,i}$ is the inside diameter of the casing (m); and $D_{t,o}$ is the outside diameter of the tubing (m).

The pressure drop in the tubing is characterized with a standard expression for the single- phase flow in the pipe with a circular cross section:

$$\Delta P_{ti} = 10^{-6}\rho g \sin(\theta_i - \frac{\pi}{2})L_i + \frac{8\times10^{-6} f_{ti} \rho L_i Q_{ti}{}^2}{\pi^2 D_{t,i}{}^5} \quad (14)$$

Where, f_{ti} the friction factor of segment i in the tubing; Q_{ti} is the axial flow rate of segment i in the tubing (m^3/s); and $D_{t,i}$ is the inside diameter of the tubing (m).

For the single-phase flow through nozzle/orifice ICDs, there should be frictional and acceleration pressure drops. However, the frictional pressure drop is normally negligible and only the acceleration effect caused by the constriction with a specified area of cross-section will be taken into account. The pressure drop across nozzle/ orifice ICDs can be calculated using the single-phase choke model of sub-critical flow (Schlumberger, 2011):

$$\Delta P_{ICD} = \frac{10^{-6} C_u \rho Q_{ICD}{}^2}{C_d{}^2 d_{ICD}{}^4} \quad (15)$$

where, C_u is the unit conversion factor, 0.81057 in SI units; Q_{ICD} is the flow rate through ICDs (m^3/s); d_{ICD} is the diameter of ICDs (m); and C_d is the discharge coefficient for ICDs.

For the single-phase flow through helical ICDs, the pressure drop across the devices can be calculated from calibration data, adjusted to allow for the varying density and viscosity of the reservoir fluid flowing through the devices (Schlumberger, 2011):

$$\Delta P_{ICD} = \left(\frac{\rho_{cal}}{\rho} \cdot \frac{\mu}{\mu_{cal}} \right)^{1/4} \cdot \frac{\rho}{\rho_{cal}} \cdot a_{ICD} \cdot Q_{ICD}{}^{2} \tag{16}$$

Where, ρ_{cal} is the density of the fluid used to calibrate ICDs (kg/m^3); μ_{cal} is the viscosity of the fluid used to calibrate ICDs (mPa·s); and a_{ICD} is the strength of ICDs, which is an empirical constant based on measurements of the calibrate fluid flow through ICDs (MPa/ (m^3/s)^2).

Coupled solution

The coupled reservoir-downhole system is nonlinear since it includes the effect of downhole hydraulics. Meanwhile, with the existence of ICDs and possible flow diversion faces, the coupling between the reservoir inflow and the downhole flow becomes more complex. An iteration approach such as the Newton-Raphson method is used to solve the nonlinear system that will converge quickly on the basis of a reasonable initial assumption. The solution procedure can also be divided into two categories. One is that flow diversion faces don't exist in the downhole flow, while the other is that flow diversion faces exist in the downhole flow. The two types of specific solution procedures are summarized as follows.

1. Flow diversion faces don't exist in the downhole flow:

1. Assume the annulus pressure distribution, P_i.
2. Use the described reservoir inflow model (Eq.12) to calculate the inflow distribution, q_i.
3. Use the described downhole flow model (Eq.13, Eq.14, Eq.15, and Eq.16) to calculate pressure drops in the annulus, tubing, and ICDs, ΔP_{ani}, ΔP_{ti}, ΔP_{ICD}.
4. Calculate the new annulus pressure distribution, $P_i^{'}$.
5. Compare the new annulus pressure distribution with the results of the last iteration. If differences are smaller than the specified tolerance, stop the process and the solution has converged; otherwise, update the annulus pressure distribution and repeat the iteration.

2. Flow diversion faces exist in the downhole flow:

1. Assume the annulus pressure distribution, P_i.
2. Use the described reservoir inflow model (Eq.12) to calculate the inflow distribution, q_i.
3. Determine the locations of flow diversion faces in the first compartment which is

close to the heel, while the judgement condition is that the pressures on both sides of flow diversion face are equal. Then, in turn determine the locations of flow diversion faces in subsequent compartments.

4. Use the described downhole flow model (Eq.13, Eq.14, Eq.15, and Eq.16) to calculate pressure drops in the annulus, tubing, and ICDs, ΔP_{ani}, ΔP_{ti}, ΔP_{ICD}.
5. Calculate the new annulus pressure distribution, P_i'.
6. Compare the new annulus pressure distribution with the results of the last iteration. If differences are smaller than the specified tolerance, stop the process and the solution has converged; otherwise, update the annulus pressure distribution and repeat the iteration.

Here, the value of the specified tolerance depends on the degree of accuracy needed in the solution procedure.

Transient-state approach

The steady-state approach can only compute the influx along the horizontal wellbore at a specific time in the well's life. To evaluate the well performance optimization effect of the ICDs completion with openhole packers throughout the well's life, a reservoir simulator is needed. With currently available reservoir simulator such as Eclipse™ capable of modeling downhole inflow control devices with openhole packers using the advanced multisegment well model method (Schlumberger, 2011), the inflow profiles over time, the time and location of water/gas breakthrough, the cumulative production, and other production parameters can be determined.

RESULTS AND DISCUSSIONS

Generally, current ICDs completions are mainly used for three production problems: the heel/toe effect caused by wellbore frictional pressure drop in a high-permeability homogeneous reservoir, imbalanced fluid inflow along the wellbore in a permeability heterogeneous sand reservoir, and uneven influx along the wellbore in a fractured carbonate reservoir. So three cases are uesd to illustrate how many openhole packers should be deployed in the ICDs completion system for different reservoir types. In all case simulation processes, an uniform ICDs completion design (the number of ICDs and the ICD flow-restriction size in all compartments are identical), which has a self-regulating function (Su & Dogru, 2009) is adopted.

High-permeability homogeneous reservoir

When horizontal wells are used in a prolific reservoir with equal permeability, the influx will be higher at the heel of the well, which will cause faster movement of the water or gas fronts toward the wellbore. This is often referred to as the heel/toe effect. The ICDs completion is believed to have the capacity for reducing the influx difference between the heel and the toe of the well. The first example involves a high-permeability homogeneous reservoir with pressure support provided by a strong bottom aquifer. The pertinent reservoir and well properties are given in Table 1. A horizontal well is placed in the middle of the oil pay and its wellbore length is 500m.

Table 1. Reservoir and well properties for case 1.

Reservoir thickness (m)	36
Distance of wellbore to WOC (m)	18
Reservoir pressure (MPa)	43
Permeability (mD)	2000
Porosity (%)	30
Formation volume factor	1.615
Oil density (kg/m^3)	840
Oil viscosity (mPa·s)	3.25
Wellbore diameter (m)	0.1397
Completion flow conduit ID (m)	0.0762
Completion flow conduit roughness (m)	0.0004

The case simulates four completion scenarios for sensitivity analysis on the number of openhole packers: (1) Barefoot completion; (2) ICDs completion without openhole packers; (3) ICDs completion with one openhole packer (two compartments); (4) ICDs completion with three openhole packers (four compartments). In all ICDs completion scenarios, to guarantee good fluid inflow equalization, the average pressure drop across the ICDs has to be equal to or higher than the pressure drop at the sandface. If the ICD flow-restriction size characterized by the flow performance curve is established, entering the average pressure drop across the ICDs, the output datum is the production rate per ICD. Dividing the total well's production rate by this output, the total number of ICDs is defined. If the number of ICDs is fixed, the flow performance curve can be used backward, starting from the production rate per ICD and selecting the suitable ICD flow-restriction size that gives the desired pressure drop across the ICDs. In this case, a total of 24 ICDs and an optimum ICD flow-restriction size (2×4mm), based on the well's specific PI and the well's production rate, are installed along the whole wellbore length. The schematic for three ICDs completion scenarios is presented in Figure 4.

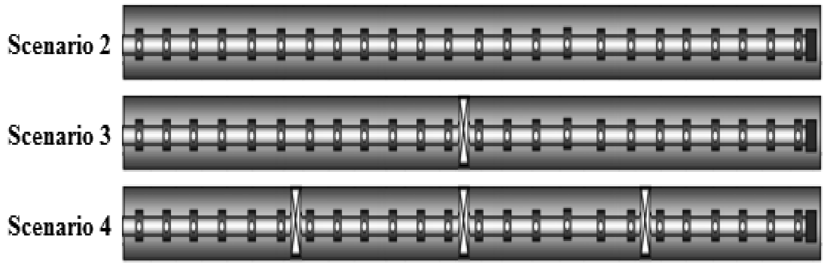

Fig. 4. Schematic of three ICDs completion scenarios (case 1).

The simulated production rate for all completion scenarios is limited to 2500m^3/d. The inflow distributions along the wellbore computed using the steady-state approach is shown in Figure 5. As we can observe, ICDs completion with no openhole packers can effectively reduce the influx difference between the heel and the toe of the well compared with barefoot completion. However, it is clear that installing openhole packers in the ICDs completion system cannot improve the degree of inflow equalization further. The observation can also be confirmed in the simulated results from the transient-state approach that include the oil and water production history (Figure 6), and the cumulative oil production history (Figure 7). When openhole packers are running, the time of water breakthrough is not delayed and the cumulative oil production is not increased compared with ICDs completion without openhole packers. Therefore, it is strongly recommended for such a high-permeability homogeneous reservoir not to use openhole packers in the ICDs completion system, because installing openhole packers not only brings no benefit to production, but also causes an increase in cost and risk.

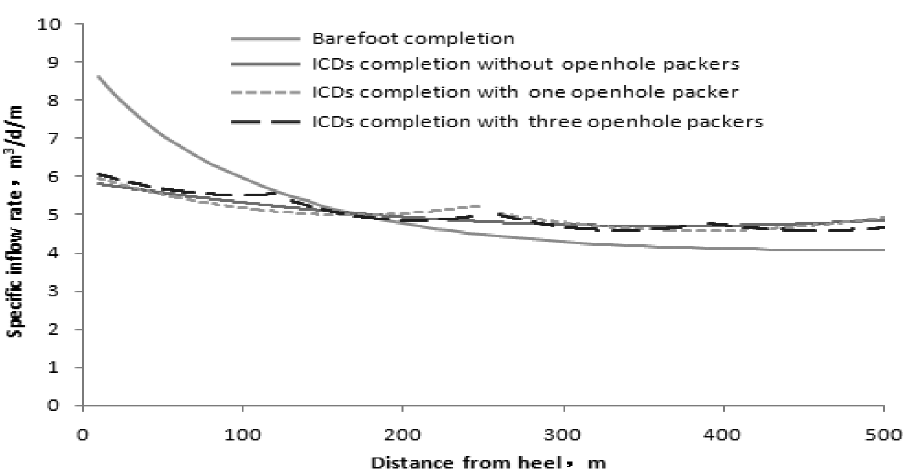

Fig. 5. Inflow profiles for four completion scenarios (case 1).

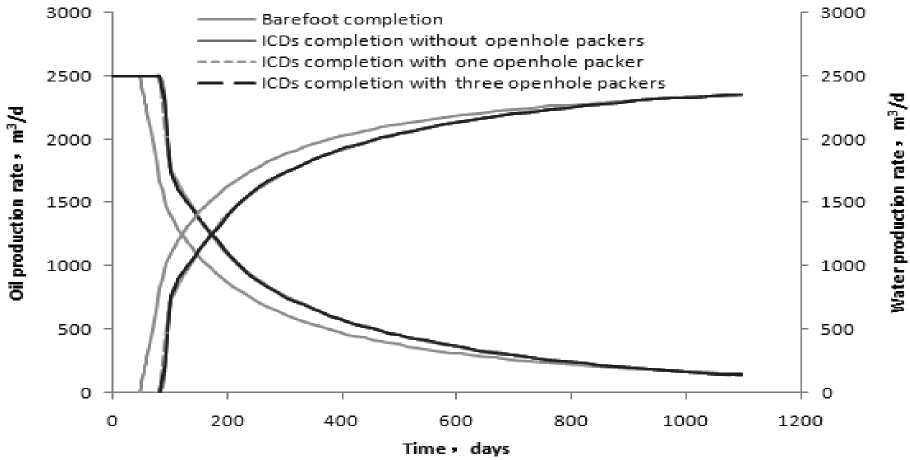

Fig. 6. Daily oil and water production for four completion scenarios (case 1).

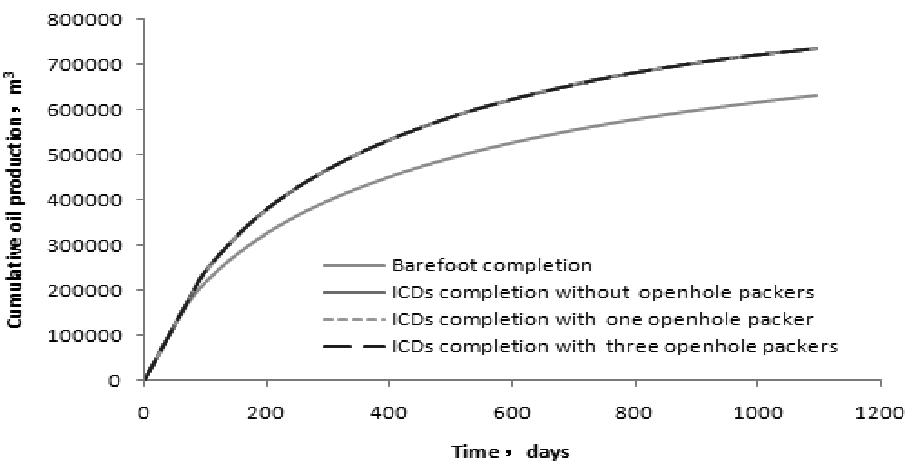

Fig. 7. Cumulative oil production for four completion scenarios (case 1).

Heterogeneous sand reservoir

For a heterogeneous sand reservoir, horizontal wells are likely to encounter different permeabilities along their wellbore length. The more permeable segments of the well will produce at higher rate and start producing water or gas earlier than other segments. Sometimes ICDs are designed to mitigate this condition and provide a more uniform production profile along the length of the horizontal well. The second example involves a heterogeneous sand reservoir with permeability ranging from 60 mD to 1050 mD along a 480 m horizontal wellbore, as shown in Figure 8. The input data for the simulation are summarized in Table 2. The lower boundary of the reservoir is surrounded by a strong aquifer.

Table 2. Reservoir and well properties for case 2.

Reservoir thickness (m)	48
Distance of wellbore to WOC (m)	28
Reservoir pressure (MPa)	54
Permeability (mD)	60-1050
Porosity (%)	20
Formation volume factor	1.5
Oil density (kg/m^3)	870
Oil viscosity (mPa·s)	5.46
Wellbore diameter (m)	0.1778
Completion flow conduit ICD ID (m)	0.102
Completion flow conduit roughness (m)	0.0004

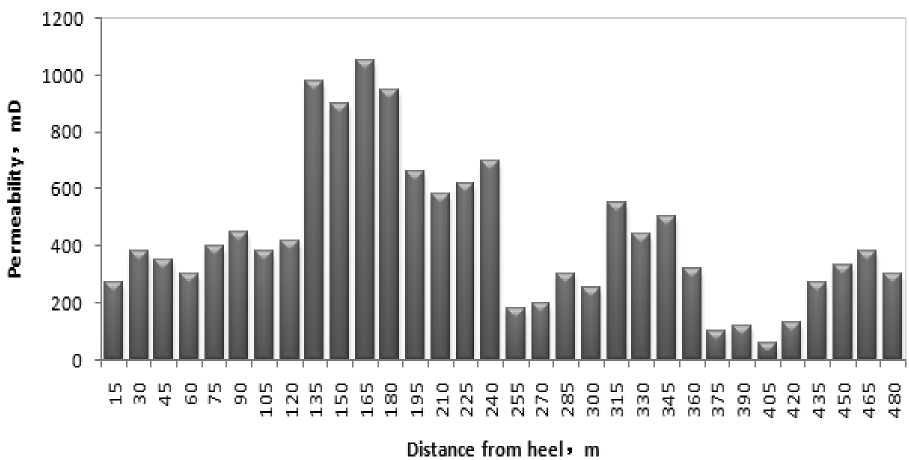

Fig.8. Permeability variations along the horizontal section (case 2).

The simulation has been running considering six completion scenarios for sensitivity analysis on the number of openhole packers: (1) Barefoot completion; (2) ICDs completion without openhole packers; (3) ICDs completion with one openhole packer (two compartments); (4) ICDs completion with three openhole packers (four compartments); (5) ICDs completion with seven openhole packers (eight compartments); (6) ICDs completion with fifteen openhole packers (sixteen compartments). In all ICDs completion scenarios, A total of 16 ICDs and an optimum ICD flow-restriction size (2×2.5mm), based on the well's specific PI and the well's production rate, are installed along the whole wellbore length. The schematic for five ICDs completion scenarios is presented in Figure 9. The simulated production rate is limited to 500m^3/d.

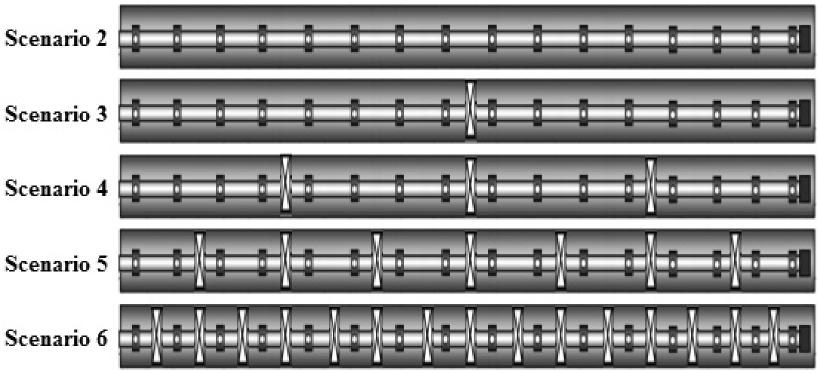

Fig. 9. Schematic of five ICDs completion scenarios (case 2).

The inflow profiles, the oil and water production history, and the cumulative oil production history for all completion scenarios are presented in Figure 10, Figure 11, and Figure 12, respectively. From these figures shown, it is clear that ICDs completion with no openhole packers can not effectively improve the production performance of the horizontal well compared with barefoot completion. This is because the reservoir fluid can freely enter the wellbore and flow in the annulus before entering the completion flow conduit through ICDs, so the equalization only happens between the annulus and the completion flow conduit, leaving high-permeability segments to dominate the production in the annulus. Meanwhile, when openhole packers are running, there is an obvious trend of positive relationship between the improvement of well production performance and the number of openhole packers. However, the optimum is reached when the number of openhole packers is seven, which means when the compartment length is equal to the reservoir permeability correlation length (60 m). Even if openhole packers are added further, the well production performance will not be improved. Therefore, for a heterogeneous sand reservoir, the simulation should be performed to find the optimum number of openhole packers which is highly related with the degree of reservoir heterogeneity.

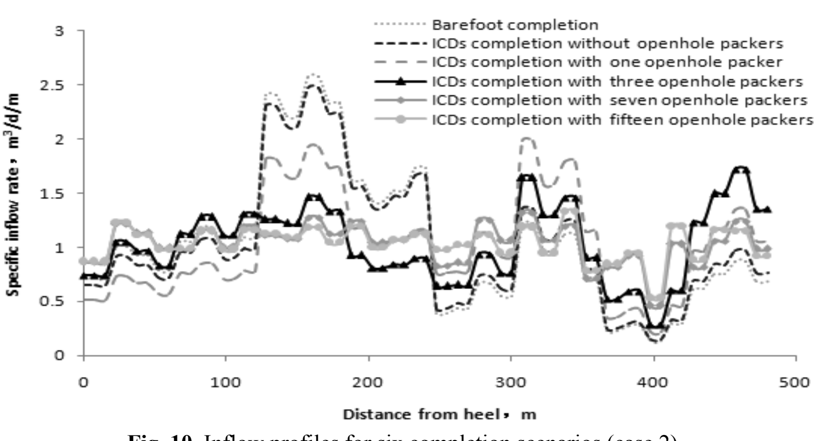

Fig. 10. Inflow profiles for six completion scenarios (case 2).

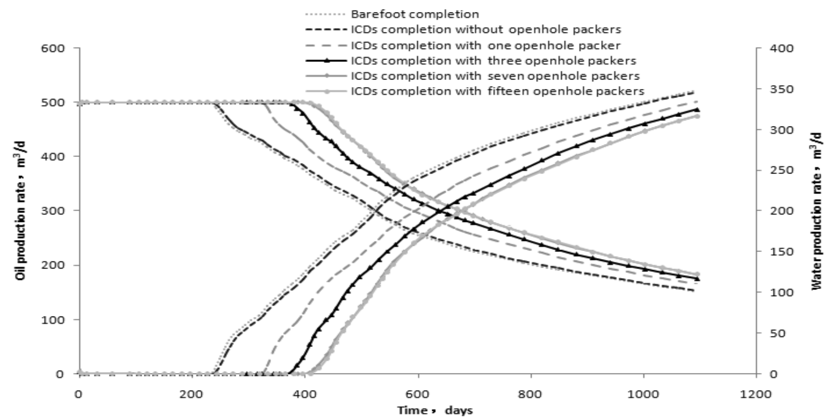

Fig. 11. Daily oil and water production for six completion scenarios (case 2).

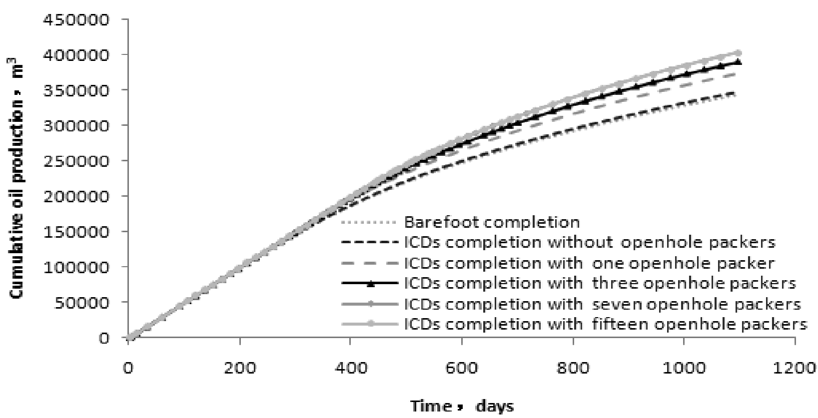

Fig.12. Cumulative oil production for six completion scenarios (case 2).

Fractured carbonate reservoir

In the case of a fractured carbonate reservoir, there is a very wide variation in permeability along the length of a horizontal well. The fractures within the reservoir tend to dominate the production of the well and be the hot spots to experience early water or gas breakthrough in the well. Installing ICDs in such a situation can control higher influx at the local fractured zones. The final example performs a fractured carbonate reservoir with the bottom water drive. A summary of the reservoir and well properties is given in Table 3. Figure 13 presents the log-derived permeability profile along a 400 m horizontal section, which indicates the heterogeneity characteristic of the reservoir and the location of fractures.

Table 3. Reservoir and well properties for case 3.

Reservoir thickness (m)	60
Distance of wellbore to WOC (m)	40
Reservoir pressure (MPa)	48
Permeability (mD)	110-5000
Porosity (%)	16
Formation volume factor	1.45
Oil density (kg/m^3)	920
Oil viscosity (mPa·s)	4.38
Wellbore diameter (m)	0.1778
Completion flow conduit ID (m)	0.102
Completion flow conduit roughness (m)	0.0004

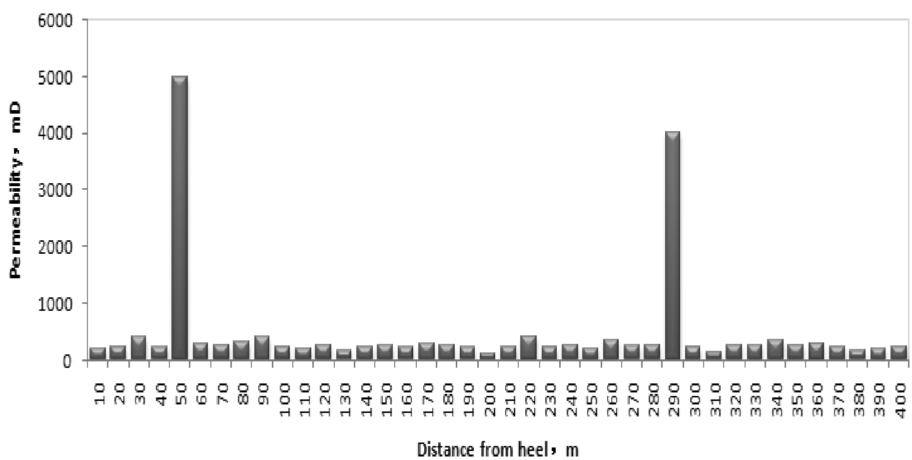

Fig. 13. Permeability variations along the horizontal section (case 3).

The case simulates six completion scenarios for sensitivity analysis on the number of openhole packers: (1) Barefoot completion; (2) ICDs completion without openhole packers; (3) ICDs completion with one openhole packer (two compartments); (4) ICDs completion with four openhole packers (five compartments); (5) ICDs completion with nine openhole packers (ten compartments); (6) ICDs completion with nineteen openhole packers (twenty compartments). In all ICDs completion scenarios, A total of 20 ICDs and an optimum ICD flow-restriction size (2×2.1mm), based on the well's specific PI and the well's production rate, are installed along the whole wellbore length. The schematic for five ICDs completion scenarios is presented in Figure 14. The simulated production rate is limited to 600m^3/d.

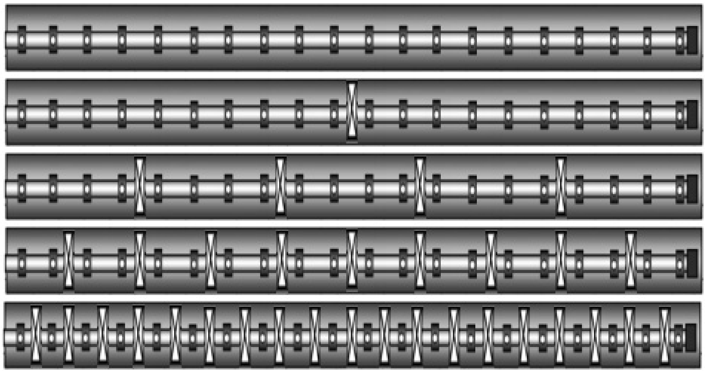

Fig. 14. Schematic of five ICDs completion scenarios (case 3).

As in the above two cases, the simulation results from the steady-state approach and the transient-state approach include the inflow distributions along the wellbore (Figure 15), the oil and water production history (Figure 16), and the cumulative oil production history (Figure 17). From these figures shown, when openhole packers are running, there is a clear trend of positive relationship between the improvement of well production performance and the number of openhole packs. The optimum is reached when the number of openhole packers is maximum, which means when openhole packers are installed along the completion at a frequency of one packer to every one ICD joint. This is because the shorter compartment can create the higher backpressure between the annulus and the inner conduit at the local fracture zones and thus make the fractures produce at a lower rate, which ultimately results in a more uniform inflow profile along the horizontal wellbore. Therefore, for a fractured carbonate reservoir, it is strongly recommended to maximize the number of openhole packers in the ICDs completion system to guarantee that there is only one ICD joint per compartment.

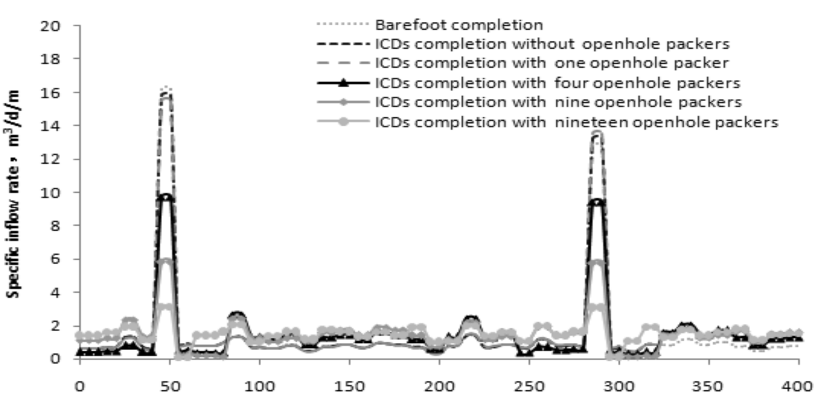

Fig. 15. Inflow profiles for six completion scenarios (case 3).

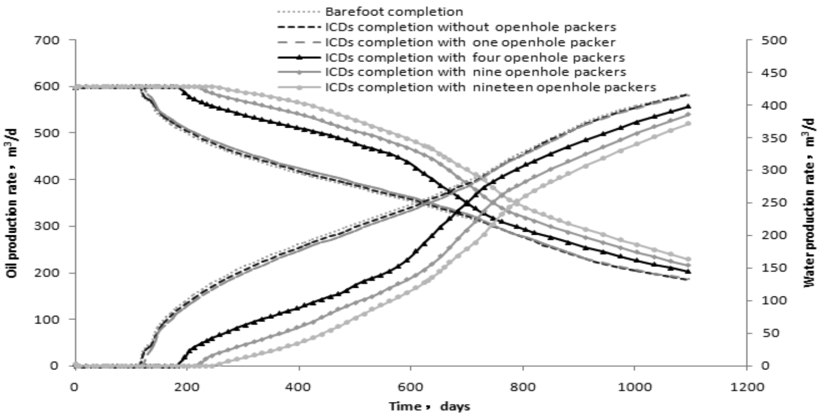

Fig. 16. Daily oil and water production for six completion scenarios (case 3).

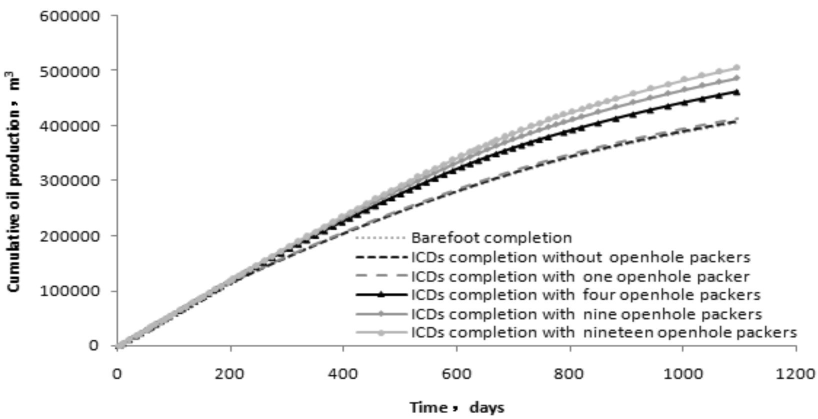

Fig. 17. Cumulative oil production for six completion scenarios (case 3).

CONCLUSIONS

In this study, the optimum number of openhole packers in horizontal wells completed by inflow control devices for different types of reservoirs has been studied. Three reservoir types that current ICDs completions are mainly used for are considered: high-permeability homogeneous reservoirs, heterogeneous sand reservoirs, and fractured carbonate reservoirs. The steady-state approach and transient-state approach are used to evaluate the effects of the ICDs completion with openhole packers on the inflow equalization and the well performance optimization. The simulation results of the study lead to the following findings:

(i) For a high-permeability homogeneous reservoir, not to use openhole packers in the ICDs completion system is the most cost-effective completion solution.

(ii) For a heterogeneous sand reservoir, the simulation should be performed to find the optimum number of openhole packers which is highly related with the degree of reservoir heterogeneity.

(iii) For a fractured carbonate reservoir, the best way is to maximize the number of openhole packers in the ICDs completion system to guarantee that there is only one ICD joint per compartment.

ACKNOWLEDGEMENTS

The authors are grateful for financial support from the National Science and Technology Major Project of China (NO.2011ZX05022-006-004HZ)

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Submitted: 13-07-2014
Revised: 13-10-2014
Accepted: 23-10-2014