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Case Study: A Fast Calculation Method on Optimizing Inflowing Control Parameters for Staged Premium Screen

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Abstract
Staged premium screen technology has been widely used in Shengli Oilfield, and works as a reliable method for sectional inflow control completion in horizontal wells. The completion plan of staged premium screen were originally optimized by flow loop test, however, the test procedure is usually as long as 12 working days. Therefore, a fast calculation method with processing time of no more than 2 days is proposed. When the well bore segmentation scheme is available, screen number as well as base pipe hole density are selected as the key parameters, and are optimized from one interval to the next on the basis of inflow control characteristics formula of staged premium screen. During the optimization of each interval, the parameters which best fit the requirements of "reasonable inflow control pressure drop" and "maximum discharge area" are determined from many alternative values. G6-P15 well, designed under the guidance of fast calculation method, obtained more balanced fluid and oil production profile versus Reference Well G6-P12. So far, 15 wells have been designed by this fast method. On average, the annual decline rate of daily oil production, the annual increase rate of water cut as well as annual mean of water cut of application wells are observed to be 36.7%, 9.4% and 7.9% lower than those of reference wells, respectively, while the annual accumulation oil production of target wells is 12.2% higher than that of reference wells. These successful applications prove that the fast calculation method has provided reasonable design.

Key words: Staged premium screen; Inflow control; Perforation density; Fast calculation method; oil production; Water cut

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INTRODUCTION

Staged premium screen completion in horizontal wells has been widely used abroad[1-5], and works as an effective way not only to balance fluid supply profile along wellbore, but also to limit the water production. The inflow control device

(ICD)[6-11], autonomous inflow control device (AICD)[12-14] as well as (autonomous) inflow control valve (ICV/AICV)[15-17] are the key components. To introduce enough pressure draw down, inflow control devices usually have smaller cross-section and longer flowing channels. However, they are easy to be plugged in actual production and are difficult to adapt to the complex production environments of reservoirs with high sand production and high shale content, which are often encountered in the development process of Shengli Oilfield. In order to solve these problems, a simple inflow control completion method, i.e. staged premium screen, is put forward and applied. This kind of screen has large drainage area, simple manufacturing process, high reliability, and is easy to be accepted by operator.

Chen Yang et al.[18] have proposed a laboratory flow loop test to effectively carry out the inflow control parameter optimization for staged premium screen completion. In order to provide a rational design and obtain a successful field application, flow tests are necessary for each target block. Therefore, the work is heavy and test procedure is usually as long as 12 working days. In order to help engineers to provide design schemes in time, a fast calculation method is proposed to optimize the inflow control parameters of staged premium screen instead of laboratory testing.

1. DESIGN PRINCIPLE OF STAGED PREMIUM SCREEN COMPLETION

Staged premium screen is a kind of sectional inflow control completion in open hole horizontal well, while the structure of completion string is illustrated in Fig. 1. During the production, a certain pressure drop will occur when the reservoir fluid passes through the screen. The pressure drop is closely related to the perforation density of the base pipe. When the perforation density is small enough, e.g. reduces from 180 holes/m to 20-50 holes/m, the pressure drop through the screen will be large enough to limit the liquid production.

During the completion design before operation, the horizontal production section of target well should be divided into several intervals in plan, then the reasonable perforation density of each interval is determined so as to control the local excessive discharge flow, and to eventually achieve balanced reservoir fluid supply along the horizontal wellbore. Due to the staged distribution of perforation density along the completion string, this completion method is defined as staged premium screen completion.

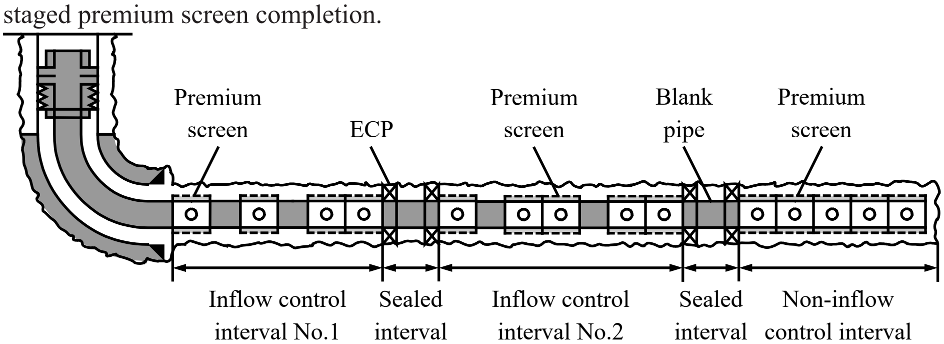


Figure 1
Staged premium screen completion string in open hole horizontal well

As illustrated in Fig.1, the production intervals are divided into two types: one is inflow control interval where the base pipe perforation density is low; the other is non-flow control interval which utilizes the conventional perforation density. In the inflow control section, screens are usually connected with blank pipe. Blank pipe does not have the passage for fluid to flow through the pipe wall, so that the screens in local interval can collect more fluid from pay zone, which is conducive to make full use of its inflow control performance. In the inflow control section, blank pipes should be spaced evenly as far as possible, and the total length of blank pipes should not be too long, i.e. the total length of screen pipes should be larger than that of blind pipes. Otherwise, it is easy to cause local fluid drainage only near the screen pipe, and is hard to give full play to reservoir production potential. In field application, the standard length of a screen is 9.8m, while the length of blind pipe is optional as needed.

External casing packers (ECPs) and blank pipes are usually applied to seal a certain length of well bore, i.e. sealed intervals, as illustrated in Fig.1. This kind of intervals are used to seal high permeability streaks as well as intervals near the oil-water surface. Even these complex situation do not exist in target wells, blank pipes and ECPs should still be run in to set up the annular isolation, especially to separate the production segments with different reservoir physical properties. The reason is that: the inflow control strength in a production interval is different with each other due to "heel-toe effect" and reservoir heterogeneity, i.e. the fluid flowing resistance through the premium screen pipe in each interval is different; Fluid always flows along the path with the lowest flowing resistance, and the liquid discharged from the pay zone around the high throttling intensity interval will be forced to migrated axially along wellbore without sealed interval, and then enter the adjacent section with low or zero inflow control intensity; Therefore, the staged premium screen will lose the acquired throttling ability.

Before planning the key parameters, it is necessary to work out the reasonable fluid allocation and inflow control pressure drop of each production interval[19]. The predicted value of daily liquid production of target well should be obtained by fully exchanging ideas with the operator. Then, according to the principle that the water breakthrough time of each interval must be the same, the single well daily production should be properly allocated into each interval to ensure the longest water breakthrough time as well as the highest oil recovery. In the process of planning a reasonable inflow control pressure drop, the principle of "the lowest inflow control draw down" should be followed, because the discharge profile is adjusted by inflow control completion at the cost of reducing productivity of single well.

2. INFLOW CONTROL PARAMETERS OPTIMIZATION

2.1 Basic Data

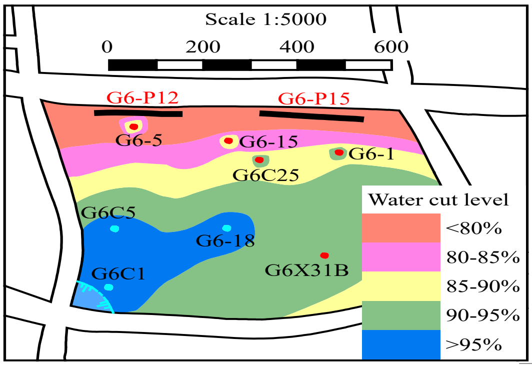


Figure 2
Well pattern and water saturation distribution in target block

As illustrated in Fig.2, the target block has a dome structure, and is surrounded by four faults. The stratum inclines to the south and the dip angle is 8° to 12°. A stable Sand Bed Sets No. 6 of Sha 4 Layer extends in the well field. This sand body is thick layered sandstones, which mainly contains siltstone with a medium-poor sorting. Well G6-P15 is selected as the target well, which locates in the upper part of pay zone (Layer No.3, Sand Bed Sets No. 6). The production segment of G6-P15 is basically parallel to the tectonic isoline. The basic parameters of reservoir, wellbore and fluid are shown in Table 1.

Table 1
The basic parameters of reservoir, wellbore and fluid

Parameters	Value
Average grain size of pay zone, mm	0.11
Average sorting coefficient of pay zone, dimensionless	1.49
Effective thickness of pay zone, m	9.8
Reservoir pressure, MPa	16.9
Average sandstone porosity of pay zone, %	27.9
Distance between reservoir top and horizontal well bore, m	1.5
Depth of target A, m	2324.0
Depth of target B, m	2530.0
Diameter of open hole wellbore, mm	215.9
Nominal diameter of screen and blank pipe, mm	127.0
Oil viscosity (standard condition), mPa·s	103
Oil density (standard condition), g/cm3	0.88

2.2 Fast Calculation Method

This part takes Well G6-P15 for example to introduce the fast calculation method. As illustrated in Fig.1, the key parameters include screen pipe number and base pipe perforation density in each inflow control section. According to the basic data of G6-P15 and pay zone in Table 1, the horizontal wellbore of target well is divided into three short production intervals with the help of segmental inflow control completion design scheme[19]. As a result, the first two are determined as inflow control interval while the last one is non-inflow control interval. The reasonable liquid allocation production q_F as well as inflow control pressure drop Δp_A of each production section are given in Table 2.

Inflow control parameters in the first production interval are sequentially designed by the fast calculation method. The steps are described as follow:

(1) List the reasonable alternative value of screen pipe number (n_P) in the first interval, e.g. when the length of this interval is 58m, n_P can take 3, 4 or 5;

(2) List the alternative value of base pipe perforation density (M_B) in the first interval, M_B ranges from 1 to 180 holes/m. A lot of experiences show that, the proper perforation density usually locates in the small part of this range. Therefore, in order to improve the calculation efficiency, the range of M_B can be narrowed appropriately, e.g. to 10-50 holes/m;

(3) Take any value of n_P and M_B to form a parameter combination, e.g. n_P takes 3 while M_B takes 10 holes/m. And then, the inflow control drawdown (ΔP) under this parameter combination can be calculated:

$$\Delta p = \frac{8.0786\times10^{-7} q_F^2 \rho_F}{\left(n_P M_B L_P\right)^2 d_H^2 C_V^2} \quad (1a)$$

Where:

$$C_V = \left(1 - e^{-0.434 d_D \mu_{FD}^{-0.1}}\right)^{0.4} \quad (1b)$$

$$d_D = \frac{d_H}{d_{BS}} \quad (1c)$$

$$\mu_{FD} = \frac{\mu_F}{\mu_{BS}} \quad (1d)$$

Where, q_F is the allocated liquid production in the first interval, m^3/s; ρ_F is fluid density, kg/m^3; L_P is single screen pipe length, usually, L_P=9.8m; d_H is sieve hole diameter, usually, d_H=0.01m; d_{BS} is the reference diameter, d_{BS}=1m; μ_F is fluid viscosity, Pa·s; μ_{BS} is reference viscosity, μ_{BS}=1 Pa·s.

(4) If Δp satisfies the following conditions, this parameter combination should be retained, otherwise it must be discarded:

$$\left|\frac{\Delta p - \Delta p_A}{\Delta p_A}\right| < \varepsilon \quad (2)$$

Where, Δp_A is the reasonable inflow control drawdown in the first interval, MPa; ε is the upper limit of relative error, dimensionless.

(5) Return to Step (3) and take the next parameter combination for calculation if the current one is rejected. If the current combination is retained, the corresponding discharge area (A) should be worked out as follow[20]:

$$A = \frac{\pi d_H^2}{4} n_P M_B L_P \quad (3)$$

(6) Circle Step (3) to (5), calculate the drainage areas corresponding to all the retained parameters combination, and select the combination which has the maximum drainage area as the key parameters in the first production interval;

Repeat Step (1) to Step (6) to optimize the inflow control parameters for the second production interval. Of course, there is no use to run the fast calculation method for the non-inflow control interval.

Relevant design software can be written on the basis of fast calculation method to work as an optimization algorithm model in the integrated optimization workflow[21], and the proper inflow control parameters can be provided no more than 2 days.

2.3 Planning Results

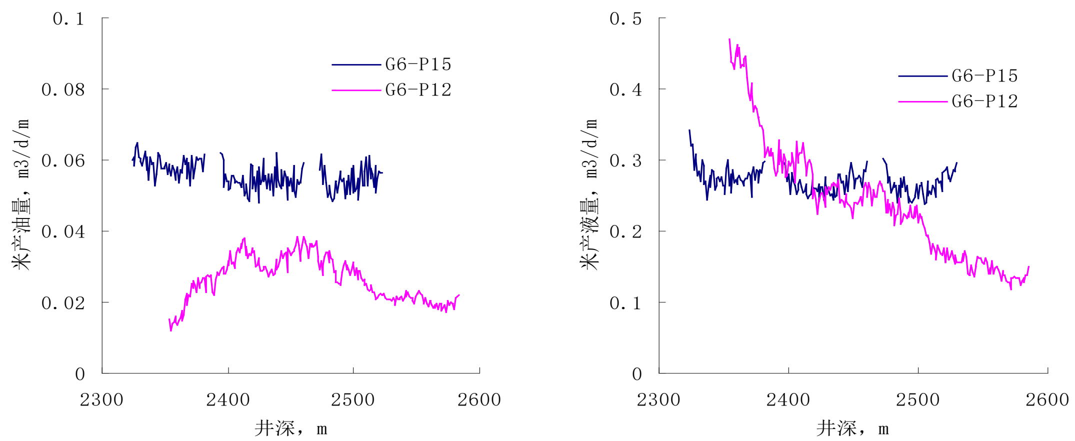
As the basic data of target well and pay zone are available in Table 1, the inflow control parameters has been processed within 32 hours with the help of fast calculation method established in section 2.2. A flow loop test[18], taking 12 working days, has also been run for G6-P15 to validate this fast method, and then the results from both methods are found to be the same as each other, as shown in Table 2.

Table 2
Design results of inflow control parameters in Well G6-P15

Well depth, m	Wellbore section	Allocated liquid production, m^3/d	Reasonable inflow control drawdown, MPa	Planned screen pipe number	Planned base pipe perforation density, hole/m	Planned blank pipe number
2324-2382	Inflow control Interval, No.1	9.3	0.50	4	22	2
2382-2394	Sealed interval	—	—	—	—	2
2394-2461	Inflow control Interval, No.2	12.2	0.39	5	25	2
2461-2473	Sealed interval	—	—	—	—	2
2473-2530	Non-Inflow control interval	18.5	0	5	180	1

3. CASE STUDY

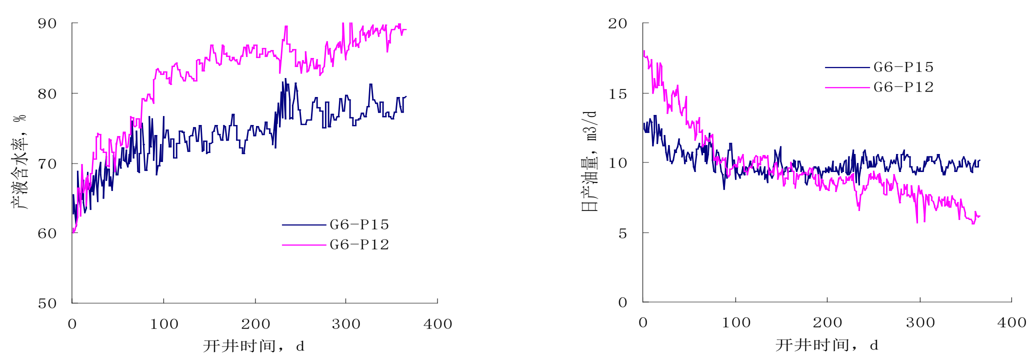
3.1 Application Results of Target Well



(a) Oil production profile (b) Liquid production profile

Figure 3
Discharge profiles of target well vs. reference well (one year after well open)

The fluid and oil production profiles of Well G6-P15 at the time of one year after well open were interpreted from production logging, and compared with those of Well G6-P12, as illustrated in Fig.3. G6-P12 is an adjacent well of G6-P15 in the same block of Fig.2, which is taken for reference and has been completed with conventional premium screen. It can be observed from Fig. 3 that, the fluid flow rate at the heel end of G6-P12 is large while the oil production is obviously inhibited, which indicates that water breakthrough has existed in this position. The production draw down at the toe is insufficient due to “heel-toe effect”, so that the local fluid and oil production are low. The discharge profile of G6-P15 is more balanced than that of G6-P12, which indicates that the staged premium screen completion has enhanced oil production in each wellbore segment, and effectively improved performance of target well.



(a) Water cut (b) Oil production

Figure 4
Daily production of Well G6-P15 vs. Well G6-P12 (in the 1st year after well open)

In the first year after well open, the production data of Well G6-P15 is compared with that of Well G6-P12. Fig.4 shows that: the annual decline rate of daily oil production (D_O), the annual increase rate of water cut (I_W), as well as the annual mean of water cut (C_W) of G6-P15 are 21.0%, 15.3% and 74.0%, which are lower than those of G6-P12 by 43.7%, 13.0% and 8.3%, respectively; While the annual accumulation oil production (Q_O) of G6-P15 is 4.1% higher than that of G6-P12.

G6-P15 has been compared with five reference wells in Block G6, as shown in Table 3. It can be observed that: D_O, I_W and C_W of target well is 35.3%, 9.2% and 8.4% lower than those average values of reference wells, respectively; While Q_O of target well is 13.0% higher than the average value of reference wells.

Table 3
Production performance of Well G6-P15 vs. reference wells (in the 1st year after well open)

Well ID	Pay zone	D_O, %	Q_O, m^3	I_W, %	C_W, %	Remarks
G6-P15	Layer No.3, Sand Bed Sets No. 6	21.0	3665.5	15.3	74.0	Target well
G6-P3	Layer No.5, Sand Bed Sets No. 6	50.3	2984.3	20.8	85.7	Reference well
G6-P5	Layer No.5, Sand Bed Sets No. 6	45.1	2863.4	21.7	84.9	Reference well
G6-P6	Layer No.2, Sand Bed Sets No. 6	60.1	3369.7	26.0	79.0	Reference well
G6-P10	Layer No.2, Sand Bed Sets No. 6	61.2	3482.0	25.8	80.2	Reference well
G6-P12	Layer No.3, Sand Bed Sets No. 6	64.7	3522.5	28.2	82.3	Reference well

3.2 Application Results in Target Blocks

So far, 15 application wells in 4 different blocks have been designed by fast calculation method, the average processing time of each well is only 31.4 hours. As shown in Table 4, the average D_O, I_W and C_W of application wells is 36.7%, 9.4% and 7.9% lower than those of reference wells, respectively, while the average Q_O of target wells is 12.2% higher than that of reference wells. It indicates that staged premium screen completion plays an important role of stabilizing oil and limit water production for application well.

Table 4
Application well performances in 4 different target blocks

Parameters		Block				Summary
		G6	C335	HZ27	T142	
Amount of application well		1	5	3	6	15
Amount of reference well		5	12	5	19	41
Average DO, %	Application wells	21.0	19.3	25.9	24.2	22.6
	Reference wells	56.3	59.2	61.2	60.3	59.3
Average Q_O, m^3	Application wells	3665.5	4269.0	3389.6	3422.3	3686.6
	Reference wells	3244.4	3756.8	3012.1	3129.9	3285.8
Average IW, %	Application wells	15.3	17.2	18.9	16.8	17.1
	Reference wells	24.5	26.3	28.0	27.1	26.5
Average CW, %	Application wells	74.0	70.5	80.2	76.8	75.4
	Reference wells	82.4	81.6	85.5	83.5	83.3

4. CONCLUSIONS

(1) A fast calculation method has been put forward to design inflow control parameters of staged premium screen completion in horizontal wells. In this method, screen number as well as base pipe hole density are selected as the key parameters. When the production section of target well is divided into several intervals, key parameters are optimized from one interval to the next on the basis of inflow control characteristics formula of staged premium screen. In the work of each interval, the parameters which best fit the requirements of "reasonable inflow control pressure drop" and "maximum discharge area" are determined from many alternative values. This fast method is friendlier to engineers than laboratory flow loop test, as it reduces the processing time from 12 days to no more than 2 days.

(2) Well G6-P15, selected as the application well, has been designed by fast calculation method. A flow loop test has also been run for G6-P15 to validate this fast method, and then the results from both methods are found to be the same as each other. At the time of one year after well open, compared with the reference Well G6-P12 completed with conventional sand control screen, the fluid production and oil production profile of G6-P15 are more balanced.

(3) The fast calculation method has optimized completion plans for 15 wells in 4 different blocks. The average D_O, I_W and C_W of target wells are 36.7%, 9.4% and 7.9% lower than those of reference wells, respectively, while the average Q_O of target wells is 12.2% higher than that of reference wells. These successful applications indicate that staged premium screen completion has effectively improved oil and water drainage state for application wells, which means that the fast calculation method has provided proper optimization results.

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