INTRODUCTION

The skin factor is the main indicator for evaluating the effect of drilling completion fluid on a reservoir. However, the skin factor obtained by field tests is the total skin factor, consisting of not only the true skin factor generated by reservoir damage near the downhole (the damaged skin factor) but also the pseudo-skin factor generated by the penetration degree, perforation, and borehole deviation. As such, correctly calculating the true skin factor of a reservoir is important for the effective evaluation of the effect of drilling completion fluid on a reservoir. Wei-hua,1 Xian-yue,2 and Li-hui3 adopted a genetic algorithm, field evaluation methods, and software evaluation methods, respectively, to make a quantitative analysis and...
calculation of the true skin factor. Frick and Economides first took the anisotropy between the reservoir interval of the horizontal wells and that of vertical wells into consideration, reporting that the anisotropic index ($I_{an}$) was the ratio between the major and the minor axes in the damaged areas. Furui and Zhu modified the anisotropic index ($I_{an}$) and took the damaged areas in reservoirs as truncated elliptic cones, which were much more coincident with the distribution of damaged areas in the horizontal intervals. Subsequently, Furui and Zhu made a differentiation of the damaged areas and presented a formula for the total skin factor based on integration, which fully considered the anisotropy of the physical properties and the extent of the damage. By coordinate transformation, Wu Xiao-dong transformed the reservoir anisotropic space into the isotropic space, obtaining an analytical formula for the skin factor. Wen-guang, Wu-zhou, and Pei-qing focused on deriving and computing skin factors of perforation completion for horizontal wells in different hydrocarbon reservoirs. Farokhi and Gerami proposed an analytical model that accurately estimated the pseudo-skin factor in a partially penetrated well, considering the impacts of anisotropy and arbitrariness in model development. The estimation result was favorably close to that obtained by a simulator. Based on a dual-well step drawdown test for the determination of hydrodynamic parameters, mechanical wellbore finite thickness skin factor, nonlinear wellbore, and nonlinear aquifer parameters in a homogeneous confined aquifer, Sethi presented a method for combining aquifer and well test data to estimate the skin factor in confined aquifer systems. Dong, Wang, and Wang used integrals along the directional well to obtain the solution for partially penetrated directionally drilled wells in an infinite slab reservoir based on the solution of a continuous point source in a laterally infinite reservoir. Then, by approximation treatment of a large-time pressure solution, a simplified skin factor model for partially penetrated directionally drilled wells was obtained.

Li et al. revisited the analytical polymer injectivity model and proposed a general form for the calculation of apparent skin factor. The apparent skin factor is estimated using polymer rheological properties, grid size, wellbore radius, etc and can apply to any polymer rheology. Using the definition of skin factor, Liu et al. defined the average permeability of a damaged area as a function of time to establish a relationship between variable skin factor and time. The variable skin factor derived was then introduced into existing traditional models, rather than using a constant skin factor, and this newly derived mathematical model for well test analysis considering variable skin factor was solved by Laplace transformation. Based on artificial neural networks, Jeirani and Mohebbi designed a new approach to estimate the initial pressure, permeability, and skin factor of an oil reservoir using pressure build-up test data. Al-Rbeawi used dimensionless pressure for steady-state flow to estimate rate-dependent skin factors (DQsc) and non-Darcy flow coefficients. Based on reservoir configurations, that is, reservoir boundaries ($2xe$ and $2ye$), wellbore length, and anisotropy, a set of plots were developed for the term DQsc. All the plots were developed based on the fact that the rate-dependent skin factor represents the difference between the total pressure drop and the pressure drop caused by Darcy flow only when the non-Darcy coefficient equals zero. Rangel-German and Samaniego presented a study aimed at obtaining a correlation for both the mechanical skin factor and the turbulence term coefficient for constant bottom hole pressure conditions through the analysis of a single test. The correlation was presented by means of straight-line fits of straw s_lywrdr.x in the vertical axis and D_mi.qsc in the horizontal axis. The correlation coefficient was 0.9976. The error obtained when evaluating the skin factor using the correlation presented in that work was less than 10%. Rahman et al. quantified permeability damage and recommended a novel perforation technique, establishing that the permeability of an open hole is reduced by 30-75% owing to implementation of the perforation by shooting technique. Ultimately, they proposed a new perforation technique termed “perforation by drilling” to remedy this problem. Based on the geological characteristics of the Longwangmiao reservoirs, Jianchun et al. applied the binomial productivity equation to demonstrate the possibility and scientificity of minimizing the skin factor. According to the current status of reservoir stimulation, the overall skin factors of reservoir damage caused by drilling fluid invasion, improper drilling, completion modes, etc were analyzed, showing that there is still potential for skin factor reduction. In order to decompose the total skin factor and implement mechanism-oriented actions to minimize the skin factor, Guo et al. optimized drilling and well completion technologies. Then, a fracture network acidizing technique that can remove “non-radial and network-like” damage by making full use of natural fractures and minimizing the skin factor was proposed to maximize well productivity. The present paper is a first attempt to compute the true skin factor $S_t$ of perforated intervals in horizontal wells by (1) combining laboratory test data and field logging data and (2) adopting an analytical formula of the true skin factor and coordinate transformation.

2.1 Experimental conditions and apparatus

The conditions for filter formation were as follows: experimental temperature $T = 90^\circ$C, pressure difference
∆P = 3.5 MPa, shear rate v = 150/s, and time t = 3600 s. An MFC-I multi-purpose damage evaluation instrument was used. The base fluid was a cationic emulsion polymer drilling fluid. The core sample comprised seven pieces of Triassic natural core. They were taken from the northwest of the South China Sea, mainly composed of semimarine deposits. The reservoir has strong heterogeneity and large permeability difference.

2.2 Experimental process

The following steps made up the experimental process:

1. The cores were cleaned, numbered, sized, and the porosity and absolute permeability of the cores were measured according to the core analysis standard method of petroleum and natural gas engineering.
2. survey the permeability $k_g$ of core samples with gas and saturate them with formation water for 48 hours;
3. survey the permeability $k_w$ of core samples by the positive formation water;
4. reverse filter the drilling completion fluid for 3600 s. (temperature of 90°C, pressure difference of 3.5 MPa, and shear rate of 150/S), record the filtration volume of the filtrate and the permeability $K_d$ of core samples, compute the temporary blocking rate $Z_d = (k_w - k_i)/k_w \times 100\%$, and check the blockage effect;
5. displace the formation water forward for flowback, gradually increase the pressure difference in the flowback, determine the breakthrough pressure of the filter cake $P_{db}$, record the flowback pressure $P_i$, and the permeability $k_{wi}$ of the core samples, and compute the permeability recovery value of the core samples $k_f = k_{wi}/k_w \times 100\%$.

2.3 Experimental results

The experimental results (Table 1) indicate that under the conditions of temperature = 90°C and pressure difference = 3.5 MPa, the filtration volume of the drilling completion fluid was less than 3 mL after 3600 s. of dynamic circulation. The drilling fluid system of the cationic emulsion polymer showed (a) a good effect in shielding temporary blocking in the reservoir, with a gas surveying permeability of less than 100 mD, a flowback recovery rate of more than 80%, and an average accumulated filtration volume of 1.645 mL and (b) for core samples with a gas surveying permeability of more than 400 mD, a flowback recovery rate of less than 60% and an average accumulated filtration volume of 1.646 mL. It is evident that this kind of drilling completion fluid system can effectively reduce the filtration loss of core samples with different permeability scales, but there is no obvious relation between the flowback recovery rate and the accumulated filtration volume; moreover, the flowback recovery rate decreases as permeability increases.

3 DAMAGE LAW OF DRILLING COMPLETION FLUID IN HORIZONTAL WELLS

In addition to heterogeneity in the degree of reservoir damage caused by the physical properties of a reservoir, both the anisotropy and heterogeneity of a reservoir should be taken into consideration when computing the true skin factor of reservoirs in horizontal wells. By analyzing the experimental results of dynamic damage evaluation, the permeability of the damaged areas in the partial reservoir intervals and the macroaxis length of the damaged ellipse can be derived.

3.1 Derivation of damaged permeability of partial reservoir intervals

By adopting a method of evaluating the dynamic damage caused by the drilling completion fluid, the damage to the tested core samples caused by the drilling completion fluid is effectively evaluated, while the method is limited to evaluate tremendous core samples. Thus, we can obtain the fitting

| Core sample | Depth (m) | $k_g$ (mD) | Total filtration volume (mL) | Natural flowback | Max recovery rate (%) | Breach pressure (MPa) | Pressure difference of max recovery rate (MPa) |
|-------------|-----------|------------|-----------------------------|------------------|----------------------|-----------------------|----------------------------------|
| Core1       | 4384.65   | 66         | 1.32                        |                  | 0.10                 | 92.20                 | 0.85                             |
| Core2       | 4380.23   | 677        | 2.60                        |                  | 0.10                 | 42.21                 | 0.10                             |
| Core3       | 4378.14   | 39         | 1.31                        |                  | 0.10                 | 83.48                 | 0.72                             |
| Core4       | 4376.32   | 37         | 1.60                        |                  | 0.20                 | 94.83                 | 1.25                             |
| Core5       | 5157.92   | 446        | 1.13                        |                  | 0.08                 | 46.47                 | 0.08                             |
| Core6       | 5157.54   | 1170       | 1.56                        |                  | 0.07                 | 11.11                 | 0.38                             |
| Core7       | 3870.82   | 62         | 2.35                        |                  | 0.06                 | 83.29                 | 1.50                             |
formula of the original and damaged permeabilities of the cores; this formula is of practical use in deriving the unknown damaged permeability from the known initial permeability only if a relatively high correlation factor is observed.

A description (Figure 1) of both the initial permeability data and the flowback recovery rate data obtained from the seven core samples yields the fitting formula $y = -0.0711x + 90.152$, with a correlation factor of 0.95, indicating that the cationic emulsion polymer drilling fluid has obvious negative regularity to the damage degree of reservoirs with different permeabilities. Therefore, it is practicable to adopt the fitting formula $y = -0.0711x + 90.152$ as the experimental derivation formula for studying the damage degree. The fitting formula is then adapted to $k_d = k_o((-0.07k_o + 90.15)/100$, wherein $k_d$ is the damaged permeability of partial reservoir intervals and $k_o$ is the initial permeability of the reservoir.

### 3.2 Derivation of the damaged semidiameater of the elliptic macroaxis of the partial reservoir intervals

#### 3.2.1 Derivation of the accumulated filtration volume of the drilling completion fluid

By analyzing the accumulated filtration data of six cores from the dynamic damage experiment of the drilling completion fluid, the relation between the accumulated filtration volume of an individual core and the time square root can be determined (Table 2). The fitting formula indicates a high correlation between these parameters, with an $R^2$ value of more than 0.96 and a maximum of 0.99, demonstrating that the accumulated filtration volume and the time square root are directly proportional. The general formula for filter loss is derived as $V_l = a t^{0.5} + b$, wherein $V_l$ is the accumulated filtration volume, mL; $t^{0.5}$ is the time square root, s; $a$ (slope) is the filtration rate; $b$ (absolute term) is the instantaneous filtration volume, mL; and the values of $a$ and $b$ depend on the permeability value.

#### 3.2.2 Establishing the macroaxis radius formula of the damaged elliptic in partial reservoir intervals

The permeability heterogeneity of the horizontal and vertical reservoir led to anisotropy in both the radial filtrate of the borehole in the horizontal wells interval and the solid invasion spreading. Therefore, the heterogeneity of the horizontal wells results in the elliptic damaged area, which is vertical to the borehole. The shape of the damaged area depends on both the damage time and the ratio between the vertical and horizontal permeabilities (Figure 2). The semidiameter $r_{dh}$ of the elliptic macroaxis in the partial reservoir intervals is computed as follows:

Assumptions: (1) the semidiameter of cores is $r_c$, m; (2) the damage time of the drilling completion fluid is $t^{0.5}$, s; (3) the length of the differentiated division of the reservoir is $\Delta l$, m; (4) the semidiameter of the borehole is $r_w$, m; (5) the saturation of the irreducible water is $S_o$, %; (6) the bulk of the macroaxis damaged zone in partial reservoir intervals is $V_r$, m$^3$; and (7) the damaged zone is symmetric, with rotating $Y$- and $Z$-axes.

According to the occupied volume of the drilling completion filtrate that invades the reservoir, the formula is presented as follows:

$$V_l = \frac{\Delta l r_w (a t^{0.5} + b)}{r_c^2} = \Phi V_r (1 - S_o) \quad (1)$$

**FIGURE 1** Relationship between the original permeability and permeability recovery value of the core sample damaged by the cationic emulsion polymer drilling fluid system
Combining Formulas (1) and (2), Formula (3) can be obtained as follows:

\[ V_r = 0.5\pi \Delta l \left( r_{dh}^2 - r_w^2 \right) \] (2)

\[ r_{dh}^2 = \frac{2r_w \left( a\sqrt{1 + b} \right)}{\Phi r_c^2 (1 - S_o)} - r_w^2 \] (3)

4 | PRECISELY COMPUTING THE TRUE SKIN FACTOR OF RESERVOIRS IN HORIZONTAL WELLS

In order to calculate the true skin factor of the reservoir intervals in the horizontal wells more precisely, logging data are used to subdivide the reservoir intervals and compute the damage skin factor of partial reservoir intervals when considering the reservoir anisotropy and drilling time effect. Then, the analytical formula of the true skin factor in the horizontal well intervals is obtained by coordinate conversion.

4.1 | Establishing a model for the damage skin factor of the horizontal wells

There are two key aspects in establishing a model for the damage skin factor of the horizontal well intervals; (1) establish the model \( S(x) \) for the damage skin factor in partial reservoir intervals, illustrating the damage degrees on the \( y-z \) plane, which is vertical to the borehole (Figure 3) and (2) according to the different damage times of the reservoirs, to present the damage distribution mode of the reservoirs along the horizontal reservoir intervals (Figure 4).

\[
V_r = 0.5\pi \Delta l \left( r_{dh}^2 - r_w^2 \right)
\]

\[
r_{dh}^2 = \frac{2r_w \left( a\sqrt{1 + b} \right)}{\Phi r_c^2 (1 - S_o)} - r_w^2
\]

4.1.1 | Model of true skin factor in partial reservoir intervals

In order to establish an analysis model for the damage skin factor at location \( X \) of the horizontal intervals, an assumption about the damage distribution on the \( y-z \) plane should be made, that is, the damaged section, which is vertical to the borehole, is parallel to the equipressure contour in Peaceman’s method, as generated by heterogeneous reservoir drifting into a circular shaft. This method proposes that the equipressure contour is the ratio between a series of macroaxes and brachyaxes, which equals 1 at the borehole and is a coaxial elliptic zone that enlarges with elongation of the off-well space. Because the reservoir damage is usually related to flow rate or flow velocity, the distribution of the reservoir damage area is assumed to be similar to the pressure field of the reservoir; in other words, the exterior boundary of the reservoir damage region is located on a equipressure contour.

By assuming the distribution zone of reservoir damage on the \( y-z \) plane, Hawkins’ formula\(^{21}\) is transformed into the analysis formula of the true skin factor for the partial reservoir intervals:
S(x) = \left( k_o \over k_d(x) \right) - 1 \ln \left[ \frac{1}{\beta + 1} \left( r_{ah}(x) \over r_w + \sqrt{r_{ah}^2(x) \over r_w^2 + \beta^2 - 1} \right) \right]
(4)

\beta = \sqrt{k_h \over k_v}

r_{ah}(x): \text{semidiameter length of macroaxis in damaged elliptic of reservoirs, m;}

r_w: \text{borehole semidiameter, m;}

k_d(x): \text{permeability of reservoir damage region, \( \mu m^2; \)}

k_o: \text{effective permeability of reservoir, \( \mu m^2; \)}

and \( \beta: \) \text{exponent of anisotropy, constant.}

4.1.2 | Model of the total true skin factor in horizontal wells

For a reservoir of homogeneous permeability, the radial flow is assumed to be the leading operator in the region around the borehole and the relational expression between the total true skin factor \( S_{eq} \) and the true skin factor \( S(x) \) of the partial reservoir intervals is obtained:

\[
S_{eq} = \frac{L}{\int_0^L \left[ \ln \left( h / \left( 2r_w \right) \right) + s(x) \right]^{-1} dx} - \ln \left[ h / 2r_w \right]
(5)
\]

In view of the anisotropic reservoir, the coordinate conversion is adopted to transform the anisotropic space of the reservoir into the isotropic space and compute the total true skin factor of the horizontal wells. The process is as follows:

Assumptions: (1) a horizontal well with length \( L \), located in the middle of an isopachous reservoir with isotropic, anisotropy, and impervious top and bottom boundaries; (2) borehole semidiameter, \( r_w; \) (3) reservoir thickness, \( h; \) (4) drainage radius, \( r_{ch}; \) (5) included angle of the horizontal interval and the X-axis, \( \phi; \) and (6) \( k_x, k_y, \) and \( k_z, \) respectively, are X-axis permeability, Y-axis permeability, and Z-axis permeability (\( k_x = k_y > k_z \)).

According to coordinate conversion theory, the original anisotropic space of reservoirs is transformed into the equivalent isotropic space by introducing the conversion factor \( T \):

\[
T = \begin{bmatrix} a & 0 & 0 \\ 0 & b & 0 \\ 0 & 0 & c \end{bmatrix}
(6)
\]

\[
a = \sqrt{k_x / k_z / \sqrt{k_x k_y k_z}} \quad b = \sqrt{k_y / k_z / \sqrt{k_x k_y k_z}} \quad c = \sqrt{k_z / k_x / \sqrt{k_x k_y k_z}}
\]

Therefore, besides the Cartesian coordinate system \((x, y, z)\), a new system \((x', y', z')\) is introduced, namely \( k = \sqrt{k_x k_y k_z} \). In addition, the geometric relation in the reservoir space changes:

\[
L' = L / \sqrt{c} \quad r_{ch}' = r_{ch} / \sqrt{c} \quad \phi' = \phi
\]

Assuming that the hole axis of the horizontal intervals in horizontal wells is parallel to the X-axis, the relation between the \( y'/z' \) coordinate system in which the borehole section is located and the \( y/z' \) coordinate system is as follows:

\[
\begin{bmatrix} y' \\ z' \end{bmatrix} = \beta^{1/3} \begin{bmatrix} 0 & 0 \\ 0 & \beta^{-2/3} \end{bmatrix} \cdot \begin{bmatrix} y \\ z \end{bmatrix}
(7)
\]

\[
\beta = \sqrt{k_x / k_z} = \sqrt{k_y / k_z}
\]

Scholar Peaceman suggests that when anisotropic reservoirs flow into a borehole, the equipressure contour around the borehole is a concentric ellipse (the ratio of the macroaxis and the brachyaxis near the borehole wall is 1) in the anisotropic space. After being transformed into the isotropic space, the equipressure contour around the borehole becomes a series of confocal concentric ellipses, and the further the equipressure contour is away from the borehole, the more its shape approximates a circle. Since, in practice, reservoir damage is usually directly related to flow velocity, the distribution shape of the reservoir damage area is similar to the distribution of the pressure field around the borehole.

After the coordinate conversion, the features of the reservoir damage area of the horizontal wells are consistent with those of reservoir percolation around the vertical fractured
wells; therefore, the true skin factor of the horizontal wells can be computed by adopting the equation for the skin factor in vertical wells and computing the macroaxis semidiameter of the two confocal concentric ellipses from both the borehole surface and the reservoir damage boundary. From experiments on core dynamic damage, the filtration velocity of the drilling completion fluid and the permeability of the damaged area are measured when core samples with different permeability degrees are under a drilling pressure difference of 3.5 MPa. The maximum invasion depth of the drilling completion fluid in the damaged areas is calculated according to the drilling time, logging data, and anisotropy coefficient.

Assumptions: (1) the macroaxis of the reservoir damage area, \( r_{dH} \) and (2) the damage permeability, \( k_d \) (neglecting the permeability change in the reservoir damage area).

Thus, in the y-z plane, two coordinate locations are known, \((r_w, 0)\) and \((r_{dH}, 0)\). The equation of the borehole surface is.

\[
y^2 + z^2 = r_w^2
\]

By inserting Formula (7) into Formula (8), the equation of the borehole surface is expressed as follows:

\[
\frac{(z')^2}{r_w (\beta^{2/3})^2} + \frac{(y')^2}{r_w (\beta^{1/3})^2} = 1
\]

Introducing Peaceman's formula\(^2\) to develop the conformal transformation gives as follows:

\[
\begin{align*}
z' &= b \cdot \cosh \rho \cdot \sin \theta_0 \\
y' &= b \cdot \sinh \rho \cdot \cos \theta_0
\end{align*}
\]

The brachyaxis and macroaxis separately are as follows:

\[
\begin{align*}
r_u &= b \cdot \cosh \rho \\
r_v &= b \cdot \sinh \rho
\end{align*}
\]

Combining Formulas (8) and (11) gives.

\[
b = \frac{r_w}{\beta^{1/3}} \sqrt{\beta^2 - 1}
\]

The given terms \((r_w, 0), (r_{dH}, 0), \) and \(b\) are substituted into Formulas (8) and (11) to compute the semidiometer of the macroaxis of both the borehole surface in the y’/z’ plane and the boundary ellipse in the reservoir damage area. The calculating formula of the total true skin factor is expressed as follows:

\[
S_{eq} = \frac{L}{\int_0^L \left[ \ln \left( \frac{\beta h}{r_w (\beta + 1)} \right) + s(x) \right]^{-1} dx} - \ln \left[ \frac{\beta h}{r_w (\beta + 1)} \right]
\]

### 4.2 Computing the damage skin factor of the reservoir intervals sectionally

Take two horizontal wells as an example for completion of sectionization-variable density perforation, and the true skin factor of the reservoir intervals needed to be computed separately according to the sectional perforation.

#### TABLE 3 Computation for \(K_d\) and \(r_{dH}\) of each perforated interval in horizontal wells

| Well name | Perforated interval (m) | Damage time (h) | Logging spots | Depth (m) | Effective permeability (mD) | Porosity (%) | Irreducible water saturation (%) | \(K_d\) (mD) | \(r_{dH}\) (%) |
|-----------|------------------------|----------------|---------------|----------|----------------------------|--------------|---------------------------------|-------------|-------------|
| W01       | 4628-4705              | 91.67-48.89    | 75            | 4628     | 8.95                       | 15.81        | 52.00                           | 8.01        | 1.88        |
|           | 4718-4796              | 43.33-0.00     | 86            | 4790     | 10.04                      | 12.61        | 45.00                           | 12.55       | 0.83        |
| W02       | 4697-4731              | 51.80-41.50    | 38            | 4700     | 104.68                     | 22.59        | 42.00                           | 86.70       | 1.24        |
|           | 4752-4815              | 35.10-16.30    | 53            | 4810     | 40.35                      | 16.40        | 45.40                           | 36.55       | 1.45        |
|           | 4825-4850              | 13.30-5.70     | 28            | 48487    | 126.10                     | 25.51        | 38.40                           | 101.70      | 1.12        |
4.2.1  |  Computing $K_d$ and $r_{dH}$ of perforating subdivided intervals in horizontal wells

Before computing the partial true skin factor $K_d$ and the damaged semidiameter $r_{dH}$ of the macroaxis, the soak time for each subdivided interval should take into consideration at first during the process of drilling and completion. The computing method was as follows: (1) calculate the average penetration speed by determining the length of the horizontal intervals and the drilling time; (2) determine the soak time of each perforated interval in the drilling completion fluid; and (3) compute the $K_d$ and $r_{dH}$ of each subdivided interval (Table 3).

A comparison between the thickness of each perforated interval and the number of subdivided intervals indicates that the dividing method approximately divides the perforated intervals into subdivisions of 1-m length. After computing the partial true skin factor of the reservoirs, Formula (12) was adopted to compute the total true skin factor of each perforated interval (Table 4), showing that the $S_d$ value of each perforated interval in the two horizontal wells was 0.21-1.67 (average 0.63). The higher the effective permeability is, the higher $K_d$ is, and the higher the irreducible water saturation is, the smaller $K_d$ is. In addition, $r_{dH}$ has a positive correlation with irreducible water saturation.

4.2.2  |  Computing the true skin factor of each perforated interval in horizontal wells

Computation results for the true skin factor are given in Table 4.

Based on the gray relational analysis method, the main controlling factors of $S_d$ of each perforated interval are analyzed, as shown in the Figure 5. The results show that the true flag coefficient has the greatest influence on permeability.

5  |  CONCLUSIONS

This paper investigates the true skin factor of perforated intervals in horizontal wells based on experimental data and logging data. The main findings and conclusions can be summarized as follows:

1. In the process of computing the true skin factor of horizontal wells, the difference between the reservoir interval in vertical wells and the reservoir damage caused by heterogeneity and anisotropy should be taken into consideration.
2. Logging data are adopted to subdivide the horizontal reservoir intervals, which are computed by the formula of

| Well name | Perforated interval (m) | Damage time (h) | Perforation thickness (m) | Differential intervals (logging spots) | Each perforated interval $S_d$ |
|-----------|-------------------------|----------------|--------------------------|----------------------------------------|-----------------------------|
| W01       | 4628-4705               | 91.67-48.89    | 77                       | 75                                     | 0.63                        |
|           | 4718-4796               | 43.33-0.00     | 78                       | 86                                     | 1.67                        |
| W02       | 4697-4731               | 51.80-41.50    | 34                       | 38                                     | 0.21                        |
|           | 4752-4815               | 35.10-16.30    | 63                       | 53                                     | 0.49                        |
|           | 4825-4850               | 13.30-5.70     | 25                       | 28                                     | 0.39                        |

FIGURE 5  Analysis of main controlling factors of $S_d$
the partial true skin factor; then, the coordinate conversion method is adopted to transform the anisotropic space into an isotropic space and the total damaged skin factor in the horizontal wells can be computed precisely.

3. If the correlation coefficient of the fitting formula is low when computing the partial damage skin factor $K_d$ and the damaged semidiameter $r_{dh}$ of the macroaxis, it can be solved by increasing the number of experiments or by adopting a different fitting formula.

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