Research Article

A Prediction Method for Flow-Stop Time in Deep-Water Volatile Oilfields: A Case Study of Akpo Oilfield in Niger Delta Basin

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Due to the difference in oil and water density, the wellhead pressure continues to decrease with water-cut rising in deep-water volatile oilfields. Once it is close to the lower limit, the production well will stop flowing. This phenomenon seriously affects the production and recoverable reserves. By taking the dynamic relative permeability which can reflect the macroscopic movement of oil and water in the reservoir as an intermediate bridge, production performance has been combined with dominant reservoir factors, including reservoir structure, reservoir connectivity, and heterogeneity. By the statistical analysis of actual data, this paper clarified the quantitative relationships between dominant reservoir factors and production performance and established the refined prediction methods for production dynamics including water-cut and liquid production rate. A prediction method for the wellhead pressure was further established, and the flow-stop time of single well can be accurately predicted. The results can be used in annual production forecast and recoverable reserve evaluation. This method had been successfully applied in Akpo oilfields in the Niger Basin. The results show that the production dynamics are significantly affected by reservoir factors in deep-water turbidite sandstone reservoir and the prediction method considering reservoir factors will be much more applicable. In deep-water volatile oilfields, the flow-stop risk of the production well in middle and high water-cut stages is very great and is mainly affected by the water-cut and liquid production rate. Judging from the application effect of Akpo oilfields, this method has high prediction accuracy and can be used to guide optimization and adjustment in deep-water oilfields.

1. Introduction

Since 2010, the global deep-water explorations have achieved a series of major breakthroughs and have become a hot target in the world [1, 2]. At present, the producing deep-water oilfields are mainly distributed in Brazil, Mexico, and West Africa [3, 4]. Among deep-water oilfields, deep-water turbidite sandstone reservoirs account for a large proportion. Due to the influence of hydrodynamic force and evolution stage, it tended to form composite spatial overlay of multistage channel sandbodies during the formation of deep-water turbidite sandstone reservoirs, and the overlay relationships between channel sandbodies are various. As a result, the reservoir structures are obviously different in different well areas even in the same oilfield [5–9].

For the reservoir structure in deep-water turbidite sandstone, predecessors have carried out a lot of research works. The method of combining wells and seismic data was used to analyze the spatial geometric relationship of composite channels from both vertical and lateral directions, and 4 types of 15 configuration styles were summed up [10]. The sandbody distribution and internal structure of the deep-water channel sedimentation system were deeply analyzed; and a set of detailed description and characterization methods were established through the analytic hierarchy process for the deep-water channel sedimentation system at three levels [11–13]. The P/S wave velocity ratio, seismic attributes, and production performance data were optimized, and the targeted qualitative and quantitative characterizations of the connected area between channel sandbodies by

demarcating the sandbody superposition area were realized. And a deep-water turbidite sandstone reservoir structure can be divided into three modes including the same-layer connection, the composite connection, and the interlayer connection [14, 15].

Floating production storage and offloading (FPSO) + floating export terminal (FET) + subsea production system (SPS) is often used for developing deep-water and ultra-deep water oilfields [16, 17]. In order to transport liquid from the SPS to the first-stage separator of the FPSO, the wellhead pressure of subsea production wells must be higher than a critical limit value. However, owing to the impact of the difference in oil-water density, the wellhead pressure of production wells will continue to decrease with the water-cut rising for deep-water volatile oilfields. Once the wellhead pressure reaches the critical limit value, the production well will stop flowing, and the production and recoverable reserves of the oilfield will be seriously affected. Generally speaking, the wellhead pressure of production wells is mainly affected by the water-cut and liquid production rate [18]. Therefore, the dynamic parameters including water-cut and liquid rate should be accurately obtained in order to forecast the flow-stop time of production wells in deep-water oilfields.

At present, many researchers have been conducted the water-cut changing law in water-flooding oilfields, which can be roughly divided into two categories as described as theoretical formula methods and empirical formula methods [19–22]. In terms of theoretical formula methods, it can be traced back to the classical theory Buckley-Leverett equation proposed by Buckley and Leverett [23], which for the first time elaborated the water flood mechanism in detail. Subsequently, Rapoport and Leas [24] extended the original Buckley-Leverett theory and deduced a differential equation that considers capillary pressure in horizontal linear reservoirs but did not solve it. Douglas et al. [25] and Fayers et al. [26] proposed a finite difference method for solving the one-dimensional water flood equation of a homogeneous oil reservoir considering the influence of gravity and capillary pressure. Chen [27] and Chang and Yortsos [28] used the relative mass flow function and comprehensively considered the effects of two-phase liquid mechanics, capillary pressure, and isothermal transient flow of gas in porous medium to establish a nonlinear parabolic partial differential equation with self-similar solution and got precise semianalytical solutions. Nieber et al. [29] and Spayd and Shearer [30] modified the Buckley-Leverett equation for two-phase flow in porous media by considering the variation of capillary pressure with saturation and determined the structures of various solutions by numerical simulation of partial differential equations. Tabatabaie and Pooladi [31] solved the fluid flow equation of two-phase linear flow in tight oil reservoirs under constant flow pressure and provided a theoretical basis for the verification of influencing factors in unconventional oil reservoirs.

Now, the mathematical models have also been expanded applicable to different types of oil reservoirs, but the theoretical equations still have some obvious shortcomings. For example, the assumptions are still too ideal, and the description of the actual oil-water mechanics is not perfect; the solving process is relatively complicated, and there is still

no suitable solution for some theoretical models. Because of these shortcomings that the theoretical model is still not directly applicable to the production decision-making of the actual oilfield.

In terms of an empirical formula, the use of waterflooding characteristic curves (WCC) has become one of the most important methods for the production dynamics prediction in waterflooding oilfields. At present, more than 100 kinds of WCC have been proposed, among which more than 10 kinds of curves are most commonly used [32]. The waterflooding characteristic curve methods mean that in waterflooding oilfields, certain dynamic parameters (such as cumulative oil/water/liquid production, water-oil ratio, and oil-water ratio) will have a linear relationship in a rectangular coordinate system or a logarithmic coordinate system, and the relationship can be used to predict production performance. Wright [33] established the semilogarithmic statistical linear relationship between water-oil ratio and cumulative production for the first time based on actual waterflooding oilfields development data. Aronofsky and Lee [34] established a semilogarithmic statistical linear relationship between oil-water ratio and cumulative oil production when studying the production performance in five-point well pattern by using hydrodynamic methods and electrical simulation experiments. After that, many Soviet scholars successively proposed many other different WCC using a large amount of actual oilfields' production data [35, 36]. In 1983, a real generalized waterflooding characteristic curve was proposed by Soviet scholars for the first time [37]. However, its application shows that the prediction error is very large and the application value is small. Since then, many scholars have done a lot of extended research on general waterflooding characteristic curve, mainly including the following aspects: the application scope and adaptability of existing waterflooding characteristic curve [38–40], theoretical derivation of existing waterflooding characteristic curve expression [41, 42], correction of existing waterflooding characteristic curve [43], and analysis of influencing factors of waterflooding characteristic curve [44].

Based on the application of the commonly used waterflooding characteristic curve, it is not difficult to find that the classical WCC are empirical formulas based on the statistics of a large amount of oilfields' production data. Hence, most WCC can only describe the water-cut changing laws of a certain type or a certain stage. For example, the waterflooding characteristic curve based on horizontal displacement process without considering gravity effect is only suitable for describing water driving characteristics of layered waterflooding oilfield [45]. And most WCC are only suitable for describing the displacement characteristics of waterflooding oilfields in medium water-cut stage [43]. Generally speaking, the waterflooding characteristic curve takes the entire oilfield as the object to predict and cannot accurately predict the production performance of a single well.

The prediction model of water-cut rising with the production time is often used to guide the development of actual oilfields. The current prediction models mainly include the logistic model, Gompertz model, and Usher model [23, 46, 47]. These models are economic, and information

FIGURE 1: A typical well of Mode I: (a) seismic section images; (b) water-cut changing law.

mathematical models directly transplanted into reservoir engineering for water-cut prediction. And the parameters' physical meaning is unclear in these models. After that, the water-cut rising prediction models were established through the derivation of seepage theory, and the prediction models of water-cut rising with the production time have a theoretical basis [48]. These prediction models have good application effects in onshore oilfields. However, as drilling costs in deep-water are very high, "less wells and higher production" becomes a consistent development strategy in these oilfields and the well spacing is always very large (1500 m~2500 m) [49–52]. As a result, the production dynamics are greatly affected by reservoir factors in deep-water turbidite sandstone reservoir [14, 22, 53, 54]. Due to the lack of in-depth analysis and consideration of reservoir factors, traditional prediction methods have poor applicability in deep-water turbidite sandstone reservoir [55–58]. In addition, due to cost and conditions, testing and adjustments are difficult to implement frequently [59, 60], which further increases the difficulty of production performance prediction.

Dynamic relative permeability is calculated based on actual production data [61, 62]. The dynamic relative permeability is very different from the conventional relative permeability measured by core experiment in deep-water turbidite sandstone reservoir. Because the relative permeability measured under experimental conditions mainly reflects the microscopic law of oil/water two-phase flow, in contrast, the dynamic relative permeability calculated based on actual production data mainly reflects the macroscopic law of oil/water two-phase flow in the reservoir [63]. In other words, the dynamic relative permeability is the result of the joint action of microscopic seepage capacity of oil/water and macroscopic reservoir conditions. Especially for deep-water oilfields which are always developed with large well spacing, the impact of reservoir factors will be much more significant. As a result, the dynamic relative permeability can better reflect the actual seepage ability of injected water under different reservoir conditions in deep-water turbidite sandstone reservoir.

In this study, the dynamic relative permeability was taken as the theoretical basis and intermediate bridge, and the quantitative relationship between the dominant reservoir factors and production dynamics was established. Combined with the actual production data considering reservoir factors, the refined production dynamics prediction method was obtained. And the prediction method for the wellhead pressure was further built. Combined with the limits of FPSO (floating production storage and offloading), the flow-stop time of each well can be accurately predicted. This method has been successfully applied to the Akpo oilfields located in the Niger Basin, West Africa, with a good effect.

2. Dominant Reservoir Factors

2.1. Reservoir Structure Mode. According to previous research results on deep-water turbidite sandstone reservoir structure, the reservoir structure can be divided into three modes [14]. And different reservoir structure mode corresponds to different production dynamic mode according to the statistics based on large amounts of data. In other words, according to the reservoir structure mode, the production dynamic mode of the target well can be initially judged.

"Mode I" is the same-layer connection (Figure 1). The injection and production wells are perforated in the channel sandbodies or sedimentary leafy sandbodies which developed during the same period (Figure 1(a)). The properties of sandbodies are similar, and the reservoir connectivity between injection and production wells is good and the reservoir heterogeneity of injection and production wells controlling area is slight [14]. The injected water has a stronger seepage ability, and the movement of waterflood front will be uniform. As a result, the water breakthrough for "Mode I" wells will be late, and the convex-shaped water-cut rapidly rises after water breakthrough. For "Mode I" wells, the water-free production period is the main production stage (Figure 1(b)).

"Mode II" is the composite connection (Figure 2). The injection and production wells are both perforated in the

FIGURE 2: A typical well of Mode II: (a) seismic section images; (b) water-cut changing law.

FIGURE 3: A typical well of Mode III: (a) seismic section image; (b) water-cut changing law.

channel sandbodies which developed during the same period and the different periods (Figure 2(a)). The reservoir properties of the channel sandbodies which developed during the same periods are relatively similar; however, the reservoir properties of the channel sandbodies are obviously different during different periods. Therefore, the reservoir connectivity between injection and production wells is relatively worse and the reservoir heterogeneity is more serious compared with “Mode I” [14]. The injected water has relatively weak seepage ability, and the movement of waterflood front will be more nonuniform than “Mode I.” As a result, the water breakthrough time for “Mode II” wells will be relatively earlier, and the S-shaped water-cut continuously rises after water breakthrough. For “Mode II” wells, the low and medium water-cut period is the main production stage (Figure 2(b)).

“Mode III” is the interlayer connection (Figure 3). The injection and production wells are perforated in the channel sandbodies which developed during different periods

(Figure 3(a)). The reservoir property is obviously different, and the reservoir connectivity is much worse and the reservoir heterogeneity is much more serious compared with “Mode I” and “Mode II.” Therefore, under “Mode III,” the injected water has the weakest seepage ability and the movement of waterflood front will be much more nonuniform than “Mode I” and “Mode II” [14].

As a result, the water breakthrough of “Mode III” wells will be the earliest, and the concave-shaped water-cut slowly rises after water breakthrough. For “Mode III” wells, the water-cut rises slowly in low water-cut period, and the water-cut rises rapidly in medium and high water-cut period. For “Mode III” wells, the medium and high water-cut period is the main production stage (Figure 3(b)).

2.2. Reservoir Connectivity and Heterogeneity. The effect of waterflooding is mainly affected by reservoir connectivity and reservoir heterogeneity between injection and production

wells [63]. Because the pressure response of production wells was the most intuitive reflection of the reservoir connectivity, the reservoir connectivity coefficient η was introduced to quantitatively characterize the reservoir connectivity between injection and production wells.

This parameter is the pressure response of production well during the interference test between injection and production wells. The larger is η , the better the reservoir connectivity will be.

$$\eta = \frac{p_e - p_i}{p_i}. \quad (1)$$

The reservoir heterogeneity coefficient T_k was introduced to quantitatively characterize the reservoir heterogeneity of injection and production wells controlling area. The closer T_k is to 1, the weaker the reservoir heterogeneity is.

$$T_k = \frac{K_h}{K_a}. \quad (2)$$

It should be noted that in addition to reservoir connectivity and reservoir heterogeneity, other factors such as well spacing and working system of injection and production well will also have an impact on the effect of waterflooding. In this article, we mainly focus on the influence of reservoir factors on production dynamics under the condition that the well pattern is fixed and the work system is basically unchanged, which is consistent with the actual situation.

3. Production Dynamic Prediction Methods

3.1. Dynamic Relative Permeability. Dynamic relative permeability can better reflect the actual seepage ability of injection water in deep-water turbidite sandstone reservoir [62]. How to quantitatively evaluate it? The relationship between oil and water relative permeability can be expressed as [64, 65]

$$K_{ro} = K_{ro}(S_{wi})(1 - S_{wd})^{n_o}, \quad (3)$$

$$K_{rw} = K_{rw}(S_{or})S_{wd}^{n_w}, \quad (4)$$

where $S_{wd} = (S_w - S_{wi}) / (1 - S_{or} - S_{wi})$.

Combining Equation (3) with Equation (4), we can get

$$\lg \left(\frac{K_{ro}}{K_{rw}} \right) = n_o \lg (1 - S_{wd}) - n_w \lg (S_{wd}) + \lg \left(\frac{K_{ro}(S_{wi})}{K_{rw}(S_{or})} \right). \quad (5)$$

Based on Equation (5), we can find out that under the same water saturation, the greater n_o and $K_{rw}(S_{or})$ and the smaller n_w , the stronger macroscopic seepage ability of injected water relative to crude oil in the reservoir, and the better the water flooding effect. Hence, the injection water seepage ability coefficient γ was introduced to quantitatively evaluate the seepage ability of injected water in the reservoir.

$$\gamma = \frac{n_o \cdot K_{rw}(S_{or})}{n_w}. \quad (6)$$

This parameter can quantitatively evaluate the macroscopic seepage ability of water phase relative to oil phase in the reservoir. The larger the γ , the stronger the macroscopic seepage ability for injected water. As a result, the movement of waterflood front will be more uniform and the sweeping area will be larger with the same water injection volume and therefore better waterflooding effect.

According to the statistics, under the same reservoir structure mode, the injection water seepage ability coefficient γ has a positive correlation with η and a negative correlation with T_k . The correspondence between η , T_k , and γ has been found (Equation (7)). The injection water seepage ability coefficient γ can be predicted according to the reservoir structure mode, reservoir connectivity, and reservoir heterogeneity of the target well by

$$\gamma = a_1 \frac{\ln(1 + \eta)}{\ln(T_k)} + a_2. \quad (7)$$

The values of a_1 , a_2 can be obtained through regression of actual data in the producing oilfields. It should be noted that we should better find oilfields similar to the target oilfield in terms of lithology, physical properties, liquids, etc. by analogy and then use the data of these oilfields to perform regression in Equation (7), so that the values of a_1 , a_2 will be more suitable for the target oilfield.

3.2. Water-Cut Rising Prediction. The water-cut rising patterns of production wells in the same mode are similar. Therefore, the water-cut rising standard curves were used to characterize the rising pattern of each mode based on the currently common water-cut prediction model [48].

$$f_{ws} = \frac{1}{b_1 + b_2 e^{-b_3 t}}. \quad (8)$$

While the standard curves can characterize the water-cut rising patterns of each mode, the water-cut rising rate of each well is quite different even in the same mode. Hence, the relative water-cut rising rate V_t has been introduced to quantitatively characterize the differences. V_t is the ratio of the actual water-cut rising rate of each well and the water-cut rising rate of the standard curves of its mode.

$$V_t = \frac{f'_w}{f'_{ws}} = \frac{df_w}{df_{ws}}. \quad (9)$$

Integrate both sides of Equation (9) to obtain the revised water-cut prediction model Equation (10) for the target well:

$$f_w = f_{ws} \cdot V_t(\gamma) + f_{w0}. \quad (10)$$

It is found that there is a good positive correlation between the coefficient γ and the relative water-cut rising rate V_t . Quantitative relations between γ and V_t for each mode

have been established by correlation analysis based on the statistics of actual production data.

$$V_t = c_1 \ln(\gamma) + c_2. \quad (11)$$

The values of parameters c_1, c_2 should be obtained in the same way as a_1, a_2 .

The relative water-cut rising rate V_t can be calculated according to the reservoir structure mode, reservoir connectivity, and reservoir heterogeneity of the target well by Equation (11). By substituting V_t into Equations (8) and (10), the water-cut rising law of each well can be predicted much more accurately.

f_{w0} is the initial water-cut of the production well. Generally speaking, dominant sedimentary facies have good thickness and physical properties, and the injected water tends to select the dominant facies for migration. The higher the thickness ratio of dominant sedimentary facies, the greater the thickness ratio of water breakthrough. Combined with actual data statistics, it is found that f_{w0} and thickness ratio of dominant sedimentary facies (h_d) are positively correlated in deep-water turbidite sandstone reservoirs. Hence, for the production wells in a water-free period, f_{w0} can be obtained by analogy to the wells with the same thickness ratio of dominant sedimentary facies.

3.3. Liquid Production Rate Prediction. For deep-water oilfields, the drawdown pressure was always kept stable. In deep-water volatile oilfields, due to the relative mobility of oil/water, the liquid production rate of the production well will continue to decrease with the water-cut rising and have a certain impact on the wellhead pressure.

The dimensionless liquid production rate (J_D) refers to the ratio of the liquid production rate under a certain water-cut to the liquid production rate during water-free production period. This parameter can be used to characterize the change of liquid production capacity of the production well with water-cut rising.

$$J_D = \frac{1}{K_{ro(S_{wi})}} \left(K_{ro} + \frac{\mu_o}{\mu_w} K_{rw} \right). \quad (12)$$

Without considering the gravity force and capillary pressure:

$$f_w = \frac{1}{1 + (\mu_w/\mu_o)(K_{ro}/K_{rw})}. \quad (13)$$

Combining Equation (12) with Equation (13), the relationship between dimensionless liquid production index J_D and water-cut f_w can be obtained:

$$J_D = \frac{\mu_o}{\mu_w} \frac{K_{rw}}{K_{ro(S_{wi})}} \frac{1}{f_w}. \quad (14)$$

As K_{rw} is also a function of f_w , the actual statistics show that the relationship between K_{rw} and f_w can be approximated as power function except for the ultrahigh water-cut

FIGURE 4: Geographic location map of Akpo oilfields.

TABLE 1: The 13 typical producing wells in Akpo oilfields.

Well	Reservoir structure	Mode
P1—P6	The same-layer connection	I
P7—P10	The composite connection	II
P11—P13	The interlayer connection	III

stage ($f_w > 90\%$). For easier application, the relationship between J_f and f_w can be simplified to

$$J_D = d_1 f_w^{d_2} + 1., \quad (15)$$

$$Q_t = J_D \cdot Q_i. \quad (16)$$

The values of parameters d_1, d_2 should be obtained in the same way as a_1, a_2 .

J_D is the dimensionless liquid productivity rate of the target well at different water-cut stage. Q_t is the liquid productivity rate of the target well at different water-cut stage. Q_i is the initial liquid productivity rate of the target well at water-free production stage, which can be calculated by traditional methods. Based on the result of water-cut rising, the liquid production rate of the target well can be accurately predicted.

3.4. Wellhead Pressure Prediction. Affected by the difference in oil/water density, the wellhead pressure will change correspondingly with the water-cut rising. Generally speaking, the pressure drawdown in the wellbore of production wells with the same well type, inclination angle, wellbore size, and perforation depth by lifting unit liquid production rate should be close under the same water-cut. Based on the pressure data statistics of typical oilfields, the relationship of the pressure drawdown in the wellbore with water cut and liquid production rate was established

$$p_{wb} - p_{wh} = e_1 f_w^{e_2} Q_t. \quad (17)$$

For a specific oilfield, production wells can be divided into several types according to TVD and well type. The parameter values e_1, e_2 of each type can be obtained by fitting the pressure monitoring data with Equation (17). As the reservoir formation pressure was kept stable for a long time with balanced

FIGURE 5: The correlation of the injection water seepage ability coefficient γ and reservoir coefficients η and T_k . (a) The correlation of the injection water seepage ability coefficient γ and reservoir coefficients η . (b) The correlation of the injection water seepage ability coefficient γ and reservoir coefficients T_k .

TABLE 2: The parameters a_1, a_2 of Equation (7) in Akpo oilfields.

Reservoir structure mode	a_1	a_2
I	0.36	0.14
II	0.31	0.03
III	0.22	0.03

injection and production rate, the reservoir static pressure can be obtained according to well testing data, and the wellhead pressure can be accurately predicted with Equation (17). In combination with the restriction conditions of FPSO, the flow-stop time of production wells can be forecasted.

TABLE 3: The parameters b_1, b_2, b_3 of Equation (8) in Akpo oilfields.

Reservoir structure mode	b_1	b_2	b_3
I	0.014	0.037	0.004
II	0.013	0.213	0.003
III	0.005	0.358	0.001

4. Application and Discussion

Akpo oilfields is located in Niger Basin, West Africa (Figure 4). The water depth is more than 1300 m. The main oil bearing interval is developed in the Neogene to Middle-

FIGURE 6: The correlation of the injection water seepage ability coefficient γ and the relative water-cut increasing rate V_t .

Upper Miocene Agbada formation, which is a deep-water turbidite sandstone reservoir formed under an overall regression environment. And the main region of the reservoir is composed of multistage channel composite sedimentary sandbodies.

Due to the influence of hydrodynamic and evolution stage, the channel sandbody's frequent unit, and overlay, the reservoir structure is complicated. The formation liquid is volatile oil; the viscosity of crude oil is 0.21 MPa·s. The average reservoir permeability is about 400 mD. Akpo oilfields have been developed by balanced water injection for more than 10 years. Up to now, most production wells in Akpo oilfields have entered the medium-high water-cut stage, the wellhead pressure has dropped significantly, and individual production wells have stopped flowing. The injection-production well spacing in Akpo oilfields is about 1500~2000 m, and the production performance of each well is diversified due to the influence of reservoir characteristics.

There were 13 selected typical producing wells in the main reservoir of Akpo oilfields. According to the reservoir structure and production performance, the typical wells can be divided into their respective modes (Table 1).

The relationship between reservoir coefficients η , T_k , and the injection water seepage ability coefficient γ of each mode can be seen in Figure 5. And the values of a_1 , a_2 in Equation (7) were obtained by fitting the actual production data of the typical producing wells (Table 2).

Fit the actual production data of 13 producing wells with Equation (8) to determine the parameter b_1 , b_2 , b_3 values of each mode in Akpo oilfields (Table 3). By statistics, the correlation between γ and the relative water-cut rising rate V_t can be seen in Figure 6. By using Equation (11) to fit the actual production data of 13 typical producing wells, the values of c_1 and c_2 were obtained (Table 4).

By using Equation (11), the relative water-cut rising rate V_t can be calculated based on the injection water seepage

TABLE 4: The constant parameters c_1 , c_2 of Equation (11) in Akpo oilfields.

Reservoir structure mode	c_1	c_2
I	0.67	1.69
II	0.41	1.70
III	0.30	1.86

ability coefficient γ . By combining Equation (8) with Equation (10), the water-cut rising law of target wells in Akpo oilfields can be predicted. And the relationship between f_{w0} and h_d in Akpo oilfields can be seen in Figure 7, which can be used to predict f_{w0} of other production wells.

Fit the actual production data of 13 producing wells with Equation (15) to determine the parameter d_1 , d_2 values of each mode in Akpo oilfields (Table 5). According to the prediction result of water-cut, the liquid production rate can be forecasted with Equation (15). Production wells can be divided into three types according to TVD and well type in Akpo oilfields. The parameter values e_1 , e_2 , e_3 of each type can be obtained by fitting the pressure monitoring data of 13 producing wells with Equation (17) (Table 6). According to prediction results of water-cut and liquid production rate, the wellhead pressure (p_{wh}) of production wells can be forecasted with Equation (17).

According to the requirement of FPSO in Akpo oilfields, the minimum pressure limit value of wellhead pressure is about 14.0 MPa. This paper selected 3 typical wells (J-01/02/03) in other reservoirs of Akpo oilfields (Table 7). The prediction results of water-cut and wellhead pressure were predicted and are shown in Figure 8. The comparison of prediction results and actual production data shows that the prediction accuracy is high (>85%).

For well J-03, the fluctuation of actual water-cut is mainly due to the increase of the drawdown pressure and the

FIGURE 7: The relationship between f_{w0} and h_d in Akpo oilfields.

injection rate, which led to a rapid rise in water-cut in the short term. Considering the fact that drawdown pressure is basically stable for a long time with the balance between injection and production in deep-water oilfields, the overall prediction is accurate.

It is found that the system error of the prediction result of the flow-stop time is about 2~3 months by comparing the actual flow-stop time of production wells in the Akpo oilfields. To further improve prediction accuracy and avoid production loss, it is recommended to advance 2 to 3 months based on the prediction results. For other oilfields, the same method can be used to determine the system error to correct the prediction result, and further improve the prediction accuracy.

The most effective way to deal with this problem in Akpo is the transformation of first-stage separators to reduce the inlet pressure limit so that the low-wellhead pressure production wells can be connected to (Figure 9).

As the number and processing capacity of first-stage separators is limited in the FPSO, it is necessary to make a reasonable transformation plan of first-stage separators according to the liquid production rate and water-cut of each production well when its wellhead pressure is close to 14.0 MPa. We must ensure that low-wellhead pressure wells can be connected to each other without affecting the normal production of other high-wellhead pressure wells.

As different modes of production wells with different production dynamics, the treatments are different:

- (1) For Mode I wells (J-01), the water-free production period is the main production stage, and the remaining recoverable reserves in high water-cut period are small. The water-cut and liquid production rate basically were kept stable in the high water-cut period, and the wellhead pressure decreases slowly and the flow-stop risk is low. Therefore, it is possible to appropriately reduce the production pressure drop-

TABLE 5: The parameters d_1, d_2 of Equation (15) in Akpo oilfields.

Reservoir structure mode	d_1	d_2
I	-0.11	0.45
II	-0.18	0.37
III	-0.40	0.18

TABLE 6: The parameters e_1, e_2, e_3 of Equation (17) in Akpo oilfields.

Well type	TVD (m)	Deviation angle (°)	e_1	e_2
Horizontal well	3000~3400	70~90	0.005	0.025
Highly deviated well	3400~3600	60~80	0.007	0.029
Directional well	3600~3800	20~60	0.009	0.034

down or increase water injection rate to increase the wellhead pressure and maintain normal production of Mode I wells

- (2) For Mode II wells (J-02), the water-cut increases continuously after water breakthrough, and the low and medium water-cut period is main production stage. In the high water-cut period, the wellhead pressure continuously decreases with the water-cut rising, and the flow-stop risk is relatively high. At first, it is possible to appropriately reduce the production pressure dropdown or increase water injection rate to increase the wellhead pressure; then the subsea production wells should be connected to the first-stage separator with lower inlet pressure limit after transformation
- (3) For Mode III wells (J-03), the water-free production period is very short, and the medium and high water-cut period is the main production stage. At the same time, the wellhead pressure rapidly decreases with the water-cut rising in late period, and the flow-

TABLE 7: Information of J-01/02/03.

Well	Well type	Reservoir structure mode	η (MPa/MPa)	T_k (mD/mD)	h_d (%)	γ	Q_i (m ³ /d)	p_i (MPa)
J-01	Horizontal	Mode I	1.75	3.2	52	0.45	2000	32
J-02	Highly deviated	Mode II	0.71	4.2	23	0.15	2500	34
J-03	Directional	Mode III	0.08	6.5	16	0.04	2500	36

FIGURE 8: The prediction results of water-cut and wellhead pressure. (a) The prediction result of J-01. (b) The prediction result of J-02. (c) The prediction result of J-03.

FIGURE 9: The transformation of first-stage separators in Akpo oilfields.

stop risk is very high. Therefore, the subsea production wells of Mode III should be connected to the first-stage separator with lower inlet pressure limit after transformation in priority

As of 2021, the inlet pressure limit of a first-stage separator has been reduced to 10.0 MPa in Akpo oilfields and 7 flow-stop wells have been connected to. The production life of these wells has been prolonged, and there is an expected cumulative oil increase of 5.0 million barrels, which has a significant effect.

5. Conclusions

- (1) The production performance of single well in deep-water turbidite sandstone oilfields is significantly affected by reservoir factors including reservoir structure, reservoir connectivity, and heterogeneity. The dynamic relative permeability can reflect the macroscopic movement of oil/water in the reservoir. Taking the dynamic relative permeability as an intermediate bridge, a refined production performance prediction method considering reservoir factors has been established, by which the water-cut and liquid production rate of single well can be accurately predicted
- (2) Combined with the production performance prediction result, the wellhead pressure and the flow-stop time of production wells can be forecasted with high accuracy. The results can be used in annual production forecast and recoverable reserves evaluation. The method has significantly improved the development technology of deep-water oilfields
- (3) The method in this paper has been successfully applied in Akpo oilfields in the Niger Basin. The prediction results have been used for the optimization and adjustment to deal with flow-stop wells by the transformation of first-stage separators, and the application effect is very good

- (4) As the relationship models in this article are based on the actual data statistics, the models are mainly applicable to deep-water turbidite sandstone reservoirs with medium and high permeability. At the same time, the innovative research ideas and work processes that taking dynamic relative permeability as an intermediate bridge to predicate production dynamics based on reservoir factors have a good reference and guiding value for other types of oilfields

Nomenclature

γ :	Injection water seepage ability coefficient (dimensionless)
η :	Reservoir connectivity coefficient (MPa/MPa)
T_k :	Reservoir heterogeneity coefficient (mD/mD)
p_i :	Initial pressure of interference test (MPa)
p_e :	End pressure of interference test (MPa)
K_h :	High permeability (mD)
K_a :	Average permeability (mD)
K_{ro}, K_{rw} :	Relative permeability of oil/water phase (dimensionless)
n_o, n_w :	The oil/water phase index (dimensionless)
S_w :	Water saturation (%)
S_{wi} :	Irreducible water saturation (%)
S_{or} :	Residual oil saturation (%)
S_{wd} :	Dimensionless water saturation (dimensionless)
$K_{rw}(S_{or})$:	Water relative permeability under the residual oil saturation (dimensionless)
$K_{ro}(S_{wi})$:	Oil relative permeability under the irreducible water saturation (dimensionless)
a_1, a_2 :	Model parameters (dimensionless)
b_1, b_2, b_3 :	Model parameters (dimensionless)
f_{ws} :	Water-cut rising standard curve of each mode (%)
f_w :	Actual water-cut of production well (%)
f'_{ws} :	Standard water-cut rising rate of each mode (dimensionless)
f'_w :	Actual water-cut rising rate of production well (dimensionless)

f_{w0} :	Initial water-cut of production well (%)
h_d :	Thickness ratio of dominant sedimentary facies (%)
t :	Days after water breakthrough (d)
c_1, c_2 :	Model parameters (dimensionless)
V_t :	Relative water-cut rising rate (dimensionless)
d_1, d_2 :	Model parameters (dimensionless)
μ_o, μ_w :	Oil/water viscosity (mPa-s)
B_o, B_w :	Oil/water volume factor (m^3/m^3)
J_d :	Dimensionless liquid production rate (dimensionless)
Q_i :	Initial liquid production rate at water-free production stage (m^3/d)
Q_t :	Actual liquid production rate at different water-cut stage (m^3/d)
p_{wb} :	Bottomhole pressure of production well (MPa)
p_{wh} :	Wellhead pressure of production well (MPa)
e_1, e_2 :	Model parameters (dimensionless).

Data Availability

The data used to support the findings of this study are inter-section within the article.

Conflicts of Interest

The authors declare that there is no conflict of interests regarding the publication of this paper.

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