Flooding mechanism of biolithite based on progressive ion exchange model: an example of the Wangxuzhuang biolithite reservoir in the Dagang oilfield

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Received 8 January 2021, revised 18 April 2021
Accepted for publication 14 May 2021

Abstract
The biolithite reservoir has a strong heterogeneity and complex pore structure, and the changing trend of formation resistivity is complicated during the waterflood development process. In the logging interpretation of a water-flooded layer, mixed-formation water resistivity is a critical parameter and its accurate calculation heavily influences the evaluation of logging water saturation. The commonly used mixed liquid resistivity models have not taken into account the contribution of irreducible clay water and, thus, they are not suitable for biolithite reservoirs with high shale contents. In this paper, a new 3D digital core was constructed based on CT scanning, and a progressive ion exchange model of the mixed-formation water compatible with the biolithite reservoir put forward. Compared with experimental data from core water flooding, the progressive ion exchange model conforms to the resistivity change law of biolithite reservoirs. Through numerical simulation and analysis of the resistivity of biolithite reservoir, it is concluded that the salinity of injected water and the formation water saturation are the main factors affecting the resistivity characteristics of water-flooded layer. In terms of the interpretation of the water-flooded layer, the water saturation was calculated using the progressive ion exchange model through finite element modelling of formation resistivity. The particular mechanism of water flooding and changing law of rock electrical properties during reservoir water injection development are presented, which provide a new reliable basis for optimization of the biolithite reservoir development plan.

Keywords: Water-flooded layer, dynamic conductive mechanism, logging interpretation, saturation model

1. Introduction
The Wangxuzhuang oilfield is a rare terrestrial biolithite reservoir that is located in the Dagang structural belt of Qikou sag in China. The reservoir is a porous biolithite reservoir with cracks. The lower Sha-1 formation of the Wangxuzhuang oilfield is the main development layer at present.
As the current main development layer, the lower member of Sha-1 is oil shale—dolomitic limestone with calcareous shale—bioclastic limestone or oolitic limestone from top to bottom. Its development and flooding characteristics are unique and complex, the development history is long, the recovery degree is not high, and the coincidence rate of logging interpretation is low.

Biolithite reservoirs have the characteristics of a complex pore structure, well-developed faults and cracks, and strong heterogeneity (Gao et al. 2002; Chen & Zhao 2004; Wang et al. 2007; Golsanami et al. 2020). Due to factors such as long-term water injection development and severe reservoir heterogeneity, the remaining oil distribution is extremely dispersed, which makes predictions increasingly difficult. As a result, it is increasingly challenging to effectively develop the remaining recoverable reserves, and further improvements in oilfield recovery are severely restricted. At present, the development direction of the research on the water-flooded layer is the comprehensive interpretation and evaluation of the water-flooded layer by using various experimental methods and combining multiple disciplines (Ci et al. 2005). However, the water injection area cannot be directly identified due to the limitations of logging tools, leading to an inaccurate interpretation of the water injection area (Liu et al. 2013; Rao & Wang 2020). The geological conditions and reservoir development conditions of major domestic oilfields are different and, thus, a complete set of logging interpretation methods have yet to be developed, especially for oilfields with low permeability after water injection.

After the oilfield is developed by water injection for a long time, some changes will take place in reservoir parameters, such as the shale content, physical parameters (porosity and permeability), electrical parameters (resistivity of mixed-formation water and rock electrical parameters), etc. Among them, the resistivity of the mixed-formation water (MFW) is an important parameter in the logging interpretation of the water injection area, and its calculation accuracy will affect that of the logging interpretation (Yong & Zhang 2002). Wei & Pan (1999) improved the traditional parallel resistivity model. They added a correction term based on the customary parallel model to express the additional conductivity formed by the contact between the formation water and injected water. The error of the model increases as the salinity gap between the original formation water (OFW) and injected water increases, which causes the model to limit the salinity of the injected water. Fang (2011) assumed that the injected water will always maintain the ion concentration balance with the OFW during the water injection development process and proposed a variable multi-material balance model. This model ignores the dynamic process of ion exchange with the flooding process, which will cause errors. Qu et al. (2018) proposed a displacement-exchange model. They believed that the original formation of water has no flowability, and the injected water enters the formation to contact the OFW and perform ion exchange. The total ion number remains unchanged before and after water injection. On this basis, Yan et al. (2017) considered the difference in the contact volume between injected water and formation water and proposed a progressively mixed saturation model, which divides the OFW into two types: large pore irreducible water and small pore irreducible water. Since all of these mixed fluid resistivity models ignore the influence of clay irreducible water, these models do not apply to biolithite reservoirs with a high shale content. As a pore scale research method, digital core technology can be used to study the changes of rock electrical properties during water injection (Nie et al. 2016). To more accurately understand the logging response characteristics and water-flooded mechanism of the water-flooded layer, this study constructed a digital core of CT scanning, proposed a new resistivity model of the MFW compatible with biolithite reservoirs and analysed the specificity of the oil displacement mechanism of the resistivity of biolithite reservoirs by finite element modelling (FEM).

2. Modelling of the 3D digital core of biolithite

At present, there are two main modelling methods for the digital core: the physical experimental method (Arns et al. 2004; Shah et al. 2014; Kelly et al. 2016) and numerical reconstruction method (Liu et al. 2015; Nie et al. 2016; Dong et al. 2020). Considering the large particle size and strong heterogeneity of the biolithite reservoir (Yang et al. 2019), the X-ray CT scanning method was chosen to construct the 3D digital core. Due to noise interference, there were isolated pixels with different grey values of 3D greyscale images. To eliminate system noise, the median filter algorithm was selected to process core 3D greyscale images (Erkan et al. 2018). The processing result is shown in figure 1.

To calculate the effective resistivity of the rock by using a 3D digital core, it is necessary to assign the corresponding resistivity value of the conductive component inside the core. The watershed algorithm is used to segment the three-dimensional grey image of rock. The watershed algorithm is a mathematical morphology segmentation method based on topological theory (Dai et al. 2019). It compares the grey value of the image to terrain with different altitudes. The grey value of each point in the image represents the altitude of this point. The area with a high grey image value is regarded as a peak, and the area with a low grey value is regarded as a valley. It slowly injects water into the valley, simulates the immersion process and observes each local minimum value and its influence area in the process of water injection. Morphologically, this area is called a catchment basin. It will expand the area according to priority, and the area of the catchment basin will continue to expand. Then, the boundary is constructed at the intersection of the two catchment basins, and
different catchment basins are separated, namely, the watershed is formed. Considering that the clay participates in electrical conduction in the form of an electric double layer, this paper classified the four pixels around the clay into clay irreducible water. At the same time, the pore space was divided into free pores and micro irreducible pores.

The irreducible water in micropores is supposed to have no mobility and, thus, the injected water could only displace the movable oil in free pores during the water injection development process. To divide the spatial distribution of irreducible pores, we used the lattice Boltzmann method to calculate the flow velocity in the core pore space and classify the position where the flow velocity is zero as irreducible pores (Akai et al. 2019). The 3D digital core of biolithite can be obtained through 3D visualization technology, as shown in figure 2. The size of the 3D digital core is $300 \times 300 \times 300 \mu m$, the porosity is 15.74% and the clay content is 14.63%. The light blue component represents the free pores, the dark blue one the irreducible pores, the white one the rock matrix, the green one the clay and the orange one shows the electric double layer on the clay surface.

Based on the 3D digital core, this paper used mathematical morphological algorithms to simulate the spatial distributions of water and oil in the free pores of the rock under different water saturations (Hilpert & Miller 2001; Meakin & Tartakovskiy 2009) and used FEM to simulate the effective resistivity of the 3D digital core (Sasaki 1994; Chen et al. 2010; Dong et al. 2017; Golsanami et al. 2021). Morphology is a method applied to image processing and pattern recognition, which can directly calculate the oil–water distribution in three-dimensional porous media. We set the initial state of pore space as full of oil. Then, the oil–water distribution in pores under different water saturations is determined by changing the element radius. Liu & Sun (2009) described this process in detail. Water saturation can be obtained by calculating total water elements including bound water and free water.

3. Construction of the progressive ion exchange model

The common mixed liquid resistivity models for calculating the resistivity of each conductive component of the core do not consider the influence of the clay irreducible water, which will bring large errors when the reservoir has a high clay content. The shale content of the biolithe reservoir in the lower Sha-1 formation of the Wangxuzhuang oilfield reflected by natural gamma logging is mainly concentrated in the range of...
Table 1. Classification of water-flooded grades of biolithite reservoirs in the lower Sha-1 formation of the Wangxuzhuang oilfield

| Flooding grades         | Water production rate |
|-------------------------|-----------------------|
| Non-watered-out stage   | ≤20%                  |
| Low watered-out stage   | 20–40%                |
| Mid-watered-out stage   | 40–80%                |
| High watered-out stage  | >80%                  |

15–30% and, thus, to understand the effect of the irreducible water in clay on the model of conductivity is key of that.

We used the water production rate to classify the water-flooded grades of the biolithite reservoir. The water-flooded grades could be divided into four categories according to the Chinese oil/gas standard (SY/T6178) water-flooded layer logging interpretation procedure, as shown in Table 1.

According to the grades of reservoir flooding, the mixed fluid resistivity model consists of four stages: a non-watered-out stage, low watered-out stage, mid-watered-out stage and high watered-out stage. This model does not take into consideration the impact of fluid and rock matrix elastic changes, assuming that the fluid produced in the formation is only caused by the injected water. There are three types of OFW: macropore free water, micropore irreducible water and clay irreducible water. Meanwhile, micropore irreducible water and clay irreducible water have no flowability. The oil–water distribution volume model in different development stages is shown in figure 3.

In the non-watered-out stage, the amount of injected water is small. The injected water at this stage is assumed only to displace the movable oil in the formation without exchange ions in OFW. Therefore, the resistivity model of water that belongs to the mixed-formation clay is a parallel connection model that includes injected water and OFW. During the low watered-out stage, the injected water exchanges ions with the free water of the macropores. The free water volume of large pores is assumed to participate in ion exchange and changes linearly during the water injection process. There is no ion exchange of the free water in the macropores and the injected water at the beginning of the stage, and the ion concentration balances are achieved at the end of the stage. In the mid-watered-out stage, the process of ion exchanges gradually appear between the injected water and the irreducible water of the micropores after achieving balance with the free water of the macropores. The total volume of macropore irreducible water does not change from the entire water injection development process due to the lack of flowability. The volume of irreducible water involved in ion exchange of the micropores is also assumed to change linearly from water injection. During the high watered-out stage, the MFW exchanges ions with clay irreducible water, which participates in the conduction of the rock through the additional exchange of cations according to the electric double layer theory.

The model hypothesis is shown in figure 3. The water saturation of the original macropore water is $S_{wi1}$, the irreducible water of stratum is $S_{wi2}$, $S_{wi3}$ represents the original total water of stratum and the original total water saturation $S_{wi}$ of the formation is expressed by

$$S_{wi} = S_{wi1} + S_{wi2} + S_{wi3}$$

The volume of the core is $V$, and the porosity is $\phi$. The current injected water volume was expressed as $k$ times the total
pore volume of the rock and, then, the cumulative injected water volume when the water saturation of the core changes from the original water saturation $S_w$ to the current water saturation $S_{wi}$ during the water injection development process is expressed as

$$Q_{tw} = k\phi V. \quad (2)$$

The production of gas and oil is equal to the increase in the formation water content:

$$Q_c = \phi V (S_w - S_{wi}). \quad (3)$$

The cumulative water production is calculated as

$$Q_w = k\phi V - \phi V (S_w - S_{wi}) = \phi V [k - (S_w - S_{wi})]. \quad (4)$$

According to the definition of the water production rate, the current water production rate formula can be expressed as:

$$F_w = \frac{Q_w}{Q_{tw} + Q_c} = \frac{k - (S_w - S_{wi})}{k}. \quad (5)$$

The relationship between the current multiple $K$ of injected water and the total water saturation can be expressed as

$$k = \left(1 + \frac{k_{ro} \mu_w}{k_{rw} \mu_w} \right) (S_w - S_{wi}) + \frac{k_{ro} \mu_w}{k_{rw} \mu_w}. \quad (6)$$

The first stage is the non-watered-out stage, in which the water production rate of the formation ($F_w$) was lower than 20%, and the beginning and ending states of the stage are $S_w = S_{wi}$ and $S_w = S_{w1}$ ($S_{w1}$ means the water saturation with $F_w = 20\%$). Due to the lower water injection, the injected water has no ions exchange with OFW. The resistivity of the MFW, as parallel resistivity of the OFW and the injected water, can be expressed as

$$S_w = \frac{S_{wi1} + S_w - S_{wi1}}{R_{w1}}. \quad (7)$$

The low watered-out moment is the second phase when the range of the formation water production rate is 20–40%. In the process of flooding, the degree of ions mixing of the free water of macropore and injected water can be presented by that of the injected water and $p$ times the volume of the macropore free water when they are completely mixed. The parameter $p$ changes linearly, that is, the volume of macropore free water participating in ion exchange with the injected water increases almost linearly. Finally, the original free water of macropore and the injected water are completely mixed, and the system finally achieves the ion concentration balance. At the beginning of this stage, $p = 0, S_w = S_{wi1}$ and at the end, $p = 1, S_w = S_{wi2}$ (where $S_{wi2}$ means the water saturation with $F_w = 40\%$). According to the equation of material balance, the total salt content of the injected water and the $p$ times the macropore free water remain unchanged. Then, the current salinity $C_{wp}$ of the mixed solution of injected water and large pore free water can be calculated as follows:

$$C_{wp} = \frac{kC_{wi} + S_{wi1} \cdot p \cdot C_{wi}}{k + S_{wi1} \cdot p}, \quad (8)$$

where

$$p = \frac{S_w - S_{wi1}}{S_{wi2} - S_{wi1}}. \quad (9)$$

The resistivity $R_{wp}$ of the mixed solution undergoing ion exchange is calculated as follows:

$$R_{wp} = \left(\frac{1}{2.74 \times 10^{-4} \times C_{wp}^{0.995}} + 0.0123\right) \times \left(\frac{81.77}{1.8T + 38.77}\right), \quad (10)$$

where $T$ is the formation temperature in degrees Celsius. The resistivity $R_z$ of the MFW can be calculated as

$$\frac{S_w}{R_z} = \frac{S_{wi2} + S_{wi3} + S_{wi1} (1 - p)}{R_{wi}} \left\{ \frac{S_w - [S_{wi2} + S_{wi3} + S_{wi1} (1 - p)]}{R_{wp}} \right\}. \quad (11)$$

The third stage is the mid-watered-out stage with the formation water production rate range from 40 to 80%, while that of formation water productivity corresponding to formation water saturation is $S_{wi2}$ to $S_{wi3}$. At this stage, the injected water and the macropore free water have been mixed and the micropore irreducible water has begun to participate in ion exchange. The degree of ions mixing of the MFW and the irreducible water of micropore can be presented by that of formation mixed water and $q$ times the volume of micropore irreducible water when they are completely mixed, where $0 \leq q \leq 1$. If the parameter $q$ changes linearly, then $q$ can be calculated as

$$q = \frac{S_w - S_{wi2}}{S_{wi3} - S_{wi2}}. \quad (12)$$

According to the ion exchange and material balance equation, the calculation formula of the salinity $C_{wq}$ of the mixed liquid is

$$C_{wq} = \frac{kC_{wi} + (S_{wi1} + S_{wi2} \cdot q) C_{wi}}{k + S_{wi1} + S_{wi2} \cdot q}. \quad (13)$$

The resistivity $R_{wq}$ of the mixed liquid in the process of ion exchange is

$$R_{wq} = \left(\frac{1}{2.74 \times 10^{-4} \times C_{wq}^{0.995}} + 0.0123\right) \left(\frac{81.77}{1.8T + 38.77}\right). \quad (14)$$
The current resistivity $R_z$ of the MFW is

$$\frac{S_w}{R_z} = \frac{S_{w1} + S_{w2} (1 - q)}{R_{wi}} + \frac{S_w - [S_{w1} (1 - q) + S_{w3}]}{R_{wi}}.$$ \hspace{1cm} (15)

The formation water production is higher than 80% in the high watered-out stage. The clay irreducible water is supposed to be fully involved in ion exchange in the beginning of the stage, and the additional conductive item of the clay is represented by Huang et al. (2009) based on the electric double layer theory as

$$C_{\text{clay}} = \varphi_{w1}^m \frac{\beta}{\alpha V_q},$$ \hspace{1cm} (16)

$$\beta = \beta_{\text{max}} [1 - 0.6 \exp (-C_w/1.3)],$$ \hspace{1cm} (17)

where $\varphi_z$ is the clay irreducible water porosity, $m_z$ is the clay pore cementation index, $\alpha$ is the diffusion factor of the balanced cation exchange layer, and $V_q$ is the pore volume occupied by the clay irreducible water when the clay cation exchange capacity is 1.

In the initial state of this stage, the salinity of the clay irreducible water can be presented by the salinity of the OFW:

$$C_{\text{clay}} = \frac{1}{R_{wi}}.$$ \hspace{1cm} (18)

Substituting equations (17) and (18) into equation (16), the following can be obtained:

$$C_{\text{clay}} = [1 - 0.6 \exp (-C_w/1.3)] C_{wi}.$$ \hspace{1cm} (19)

The salinity $C_w$ of the MFW is calculated as

$$C_w (k + S_w) = k \cdot C_{wi} + (S_{w1} + S_{w2}) \cdot C_{wi} - 0.6 \exp (-C_w/1.3) \cdot C_{wi} \cdot S_{w3}.$$ \hspace{1cm} (20)

Through numerical iteration, the salinity $C_w$ of the MFW can be obtained. Then, the resistivity $R_z$ of the MFW is calculated as:

$$R_z = \left( \frac{1}{2.74 \times 10^{-4} \times C_w^{0.995}} + 0.0123 \right) \left( \frac{81.77}{1.8T + 38.77} \right).$$ \hspace{1cm} (21)

4. Application and analysis

4.1. Model discussion

For confirming the quality of the results of numerical simulation in the progressive ion exchange model (PIEM), the mathematical morphology algorithm was used to simulate the oil–water distribution in the pores under different water saturation conditions in the water-flooding phase, which was based on the target reservoir biolithite by a 3D digital core model. The resistivity model of rock was calculated by FEM, and the resistivities of different components, such as clay, clay irreducible water, formation water and rock matrix, in the rock were used as input parameters. Figure 4 shows the comparison between the resistivity calculation results of the 3D digital core, which is based on the displacement-exchange model, the progressive mixed saturation model, the PIEM and the core experiment results. In the case of high-water saturation, the change in resistivity of the displacement-exchange model is obviously lagging, and the resistivity value is too low. The main reason is that the displacement-exchange model regards the OFW as a whole and ignores the different degrees of mixing of the injected water and the irreducible water of different pores in the formation during the flooding process. The two progressive models are basically consistent with the overall trend of the experimental data. Among them, the progressive mixed model ignores the influence of the cation exchange of the electric double layer, which causes the error to gradually increase after the water saturation exceeds 70%. However, the PIEM is always in good agreement.

Since the process of ion exchange in the OFW and injected water, not only does the resistivity of injected water change along the core conductive path, but the resistivity of the OFW also changes with different salinities of the injected water. Therefore, even in the case of injected water with the same injection multiple, the resistivity of the formation water changes significantly with the salinity of the injection water changes.

To investigate the effect of the resistivity of the injected water on the mechanism of resistivity variation in the water-flooded layer, the numerical simulation and experimental study of the water-flooded rock resistivity with multi-salinity were carried out under simulated reservoir conditions.
Figure 5. The profile curve of core resistivity with different water saturations.

Figure 5 presents the changing relationship of formation resistivity with water saturation of TSD of the 600, 5000, 8000 and 15 000 mg L\(^{-1}\) injected water, respectively, under the conditions of the TSD of the OFW of 15 000 mg L\(^{-1}\) at the original reservoir temperature of 70°C.

The results from the numerical simulation showed that during the water injection development process, the variation regularity of the formation resistivity in water-flooded layers of the biolithite reservoir changed when injected water salinity was different from the salinity of the OFW.

There are two main reasons for the change in the formation resistivity caused by injected water: (i) the movable oil is displaced by injected water, which increases the water saturation and decreases the core resistivity and (ii) the injected water exchanges ions with the OFW, resulting in an increase in the core resistivity.

The resistivity of the core shows a monotonously decreasing trend with different water saturation when the ratio of injected water salinity and the salinity of OFW is approximately one. The reason is that the OFW salinity and injected water salinity are almost the same and, thus, the resistivity of the core is only affected by the water saturation. Then, as the value of \(C_{wp}/C_w\) gradually decreases, the relationship of the increase between the water saturation and resistivity presents an unsymmetrical S-shape. According to the curve trend, the variation process of the core resistivity can be defined as appearing in three phases: the initial phase, the middle phase and the later phase of water injection. In the first phase, the effect of the ion exchange of mixing water is not enough to offset the effect of water saturation on the resistivity of rock due to the small amount of injected water, and thus the rock resistivity increases gradually at this stage. In the middle stage of water injection, the ion exchange phase between the OFW and injected water is sufficient, and the curve of the core resistivity is gradually dominated by ion exchange and shows an upwards trend.

In the last phase, the ion exchange of MFW is basically complete, and thus, the resistivity of core gradually reduces with the increase of water saturation. As the value of \(C_{wp}/C_w\) decreases, the curve of the core resistivity is dominated by the change of water saturation and presents a monotonous decreasing trend.
continues to decrease, the curve trend of the resistivity with water saturation changes from S-type to a reverse L-type; that is, the tendency towards resistivity decreases at first and then increases. The value of the resistivity is considerably higher than that of the initial state when the displacement is completed. It can be observed that the rise of the formation resistivity is affected by the injected water salinity. The lower the injected water salinity, the higher the injected water resistivity and the more obvious the rise is.

4.2. Well log application

A three-parameter joint quantitative iteration was used to solve the PIEM, which involves three unknown parameters: water saturation $S_w$, mixed liquid resistivity $R_z$ and water production rate $F_w$. The water saturation calculated based on the resistivity of the OFW is used as the value of the initial water saturation of the iterative process. Then, the PIEM can be used to sequentially calculate the water production rate, the oil–water relative permeability and the resistivity of the mixed liquid by combining the initial water saturation, the experiment of phase permeability and the injected water resistivity with the fluid viscosity in the formation. Another value of the water production rate is obtained by iterative calculation using the resistivity calculation result of the mixed solution according to these steps. When the error of the two water production rates meets the set error range (eps), the water saturation, water production rate and the resistivity of the mixture are the appropriate values required. The verification analysis of the PIEM based on the programming of the three-parameter joint quantitative iterative process is presented in figure 6.

Figure 7 presents the well-logging interpretation of Qi 646–2 in the lower Sha-1 formation of the Wangxuzhuang oilfield.
oilfield. The sixth column in the figure shows the water saturation, which includes the results calculated by core analysis, the progressive mixed model and the PIEM. The results show that the accuracy of the PIEM is significantly improved compared with that of the progressive mixed saturation model when the shale content is relatively high.

The mean absolute error calculated by the PIEM is 1.93%, which reaches the fine evaluation standard of the water-flooded layer. Therefore, the feasibility of the PIEM in calculating the water saturation of the biolithite reservoir of the lower Sha-1 formation of the Wangxuzhuang oilfield is verified.

5. Conclusions

(1) Based on the digital core technology, we determined the PIEM of the MFW in the biolithite reservoir and simulated the flooding mechanism of the biolithite. Compared with the experimental data of core water flooding, the PIEM conforms to the resistivity change law of biolithite reservoirs.

(2) The resistivity of biolithite reservoirs is numerically simulated and analysed based on digital core technology. The main factors affecting the resistivity characteristics of water-flooded layer are the salinity of the injected water and the formation water saturation. When the OFW salinity is higher than that of the injected water, the resistivity curve of reservoir can be defined as being one of three types: monotonically decreasing, ‘S’ type and reverse ‘L’ type.

(3) In terms of the interpretation of the water-flooded layer, the water saturation was calculated using the PIEM based on the fine modelling of nine key parameters, including the shale content, irreducible water saturation, porosity, oil—water relative permeability, permeability and residual oil saturation. The average absolute error of the model is small, and thus this model provides a reliable basis for the optimization of the biolithite reservoir production plans.

Acknowledgements

This work was supported by the National Science and Technology major project (grant no. 2016ZX05006002-004), the National Natural Science Foundation of China (grant no. 41874138), the Shandong Provincial Natural Science Foundation, China (grant no. ZR2020QD054), the China Postdoctoral Science Foundation funded project (grant no. 2019M662463), the Youth Program of National Natural Science Foundation of China (grant no. 42004098) and the Fundamental Research Funds for the Central Universities (grant no. 20CX06026A).

Conflict of interest statement. None declared.

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