Research Article

Study on Fracture Characteristics and Controlling Factors of Tight Sandstone Reservoir: A Case Study on the Huagang Formation in the Xihu Depression, East China Sea Shelf Basin, China

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Natural fractures are not only the key to affect the natural productivity of tight sandstone reservoirs but also one of the important factors to control the fracturing effect. If the local strata are affected by multistage tectonic movement and diagenesis, it will lead to the complexity of fracture types and characteristics, which makes it difficult to accurately identify natural fractures, thus, seriously affect the development of fractured reservoirs and the fracturing effect. In this paper, the macroscopic fractures were studied by combining core, conventional logging, imaging logging, petrophysical logging, logging, drilling, and gas test data. The microscopic fractures were analyzed by casting thin sections and scanning electron microscopy and cathodoluminescence. The effect of fractures on hydrocarbon migration was analyzed by fluid inclusions in fractures. The core can be used to visually study the opening fracture, but when the color of the filling inside the fracture is similar to the surrounding, the filling fracture is not easy to be found. Imaging logging has high identification accuracy for filling fractures, but it can hardly be used as a means of identifying high-angle opening fractures. The opening fracture zone in the noncoring section can be studied by conventional logging, mud logging, drilling, and rock mechanical parameter. The macroscopic structural fractures are obviously directional, which is controlled by the tectonic stress field. The occurrence and density of macroscopic structural fractures are controlled by buried depth, lithology, rock thickness, sedimentary facies, distance from the fault, and structural location. The opening fractures are all of high angle, indicating that the inclination angle is an important factor affecting the filling degree of fractures. The direction of intragranular fractures is chaotic, which is affected by the mechanical weak surface of the mineral particles, particle morphology, and particle contact relationship and stress. Effective fractures provide channels for the migration of oil and gas and acidic fluids in the historical period, which promote the occurrence of hydrocarbon accumulation and dissolution.

1. Introduction

For conventional reservoirs, porosity and roar are the main factors affecting reservoir quality [1, 2]. In reservoirs having low host-rock permeability-dense, natural fractures are one of the key factors that improve reservoir physical properties and increase productivity, as well as the important factors restricting the fracturing effect [3–5]. Although scholars have conducted extensive research on fractures [6, 7], understanding the origin and attributes of subsurface fractures is still a worldwide concern. One of the main reasons why fracture research has encountered such a bottleneck is that the types of fractures are complex. In addition, there are many factors that affect the development of fractures, which have different effects on fractures in different types of petroliferous basins [8–11]. Therefore, for a specific oil and gas field, it is necessary for scholars to conduct targeted research on fracture types and control factors. Only by thoroughly understanding the types of reservoir fractures and the controlling factors of major fractures, scholars can select appropriate methods and techniques to predict fractured reservoirs to provide guidance for exploration and development [12].
The Xihu Depression is a typical offshore oil and gas field with few wells. The lower part of the Huagang Formation is dominated by low permeability-tight reservoirs [13, 14]. For the high failure rate of Huagang tight reservoir fracturing, in addition to the immature offshore fracturing technology, the unclear understanding of the Huagang Formation fractures is an important reason. Core and imaging logging are commonly used for macroscopic fracture visual identification [15]. This study found that both of the above two methods have shortcomings in application. The open high-angle shear fractures can hardly be recognized by imaging logging, and the filling fractures with similar colors to the surroundings are easy to be ignored during core observation, which lead to an inaccurate grasp of fracture development rules in the previous studies. In order to avoid the above problems, this paper identified filling fractures by using imaging logging and studied opening fracture zone by core, logging, drilling, gas testing, conventional logging, and petrophysical logging. The microscopic fractures were observed and counted by casting thin section, scanning electron microscope, and cathodoluminescence. The influencing factors of macroscopic structural fractures were analyzed, and the controlling factors of microscopic fractures were tentatively discussed. Finally, the macroscopic and microscopic fractures were analyzed. The evaluation of fracture effectiveness provides technical support for the development of the Huagang Formation tight sandstone reservoir in the study area and provides method reference for the development of offshore deep tight sandstone oil and gas resources.

2. Geological Setting

The Xihu Depression is located in the middle of the eastern depression of the East China Sea Shelf Basin, which is the largest oil-bearing basin in the offshore area of China [13, 16]. The Xihu Depression experienced three main deformation stages including faulting period associated with normal faults, depression period that is the main fracture forming period, and overall settlement period. The early Pinghu Formation is in fault depression period, the mid-Huagang Formation ~ Liu Lang Formation is in depression period, and the late Santan Formation-Donghai Group is in overall settlement period [17–19]. The Xihu Depression can be divided into the western slope zone, the western subrecess zone, the central inversion tectonic zone, the eastern subrecess zone, and the eastern fault zone [20] (Figure 1). During the depression period, under the combined subduction of the Pacific Plate and the Philippine Plate, the central uplift belt developed a large number of north-north-east anticline zones. At the same time, a north-north-east reverse fault was generated on the limb of the anticline [21, 22].

There are two kinds of sedimentary environments in the Xihu Depression from Eocene to Miocene. The Marine sedimentary environment is mainly composed of bay delta facies, bay tidal flat facies, and bay shallow sea facies. The continental sedimentary environment can be further divided into braided fluvial facies, braided deltaic facies, and lacustrine facies Li et al. [23]. The reservoirs are mainly distributed in the Huagang Formation, and the main source rock is the underlying coal seam of the Pinghu Formation, with the peak of hydrocarbon expulsion in the middle Miocene. The main sedimentary facies of the Huagang Formation is braided river delta front, with large sand body thickness of over 100 m, and total gas reservoir thickness of over 400 m, which has a good development prospect Cao [24].

The study area in this paper is a typical wide anticline on the central uplift. The fault is dominated by the reverse fault that is aligned with the long axis of the anticline and developed on the limb of the anticline. There are totally 4 wells drilled at the top of the wide anticline. The target layer of this research is the Huagang Formation, with a development depth of about 3 600 m ~4 200 m. The conventional, low-permeability, and tight reservoirs are all developed in this study area with strong heterogeneity.

3. Methods

200 m cores (4 wells) were observed in this study. 10 samples of sandstone were taken for scanning electron microscopy, and 7 samples of sandstone were taken for inclusions. Other information was all provided by CNOOC LIMITED, including more than 300 pieces of casting thin sections and more than 40 pieces of cathode luminescence lamellae, conventional logging, imaging logging, logging data, drilling data, gas testing data, and production performance data of four wells.

In this study, core, conventional logging, imaging logging, drilling data, and logging data were used to identify macroscopic fractures. First, the types and characteristics of macroscopic fractures were observed and counted through the core. By comparing the observation results of core fractures with imaging logging, it is concluded that imaging logging is the most effective method to observe filling fractures. It can not only clearly identify the existing location of filling fractures but also count the occurrence, quantity, and strike of fractures. However, imaging logging can hardly identify macroscopic fractures, which is also the main reason that why the previous researchers thought that natural macroscopic fractures did not develop in the study area. At the same time, it is found that there are many omissions in the identification of completely filled fractures by core observation, especially when the color of the filling material in the core is similar to the surrounding color.

The identification of opening macroscopic fractures is mainly completed through the following steps: mark the opening macroscopic fractures observed by the core to the corresponding depth of each well; then analyze the characteristics of drilling time curve, mud loss, and conventional logging curve of the depth section near the opening fractures; and summarize the identification chart of opening fracture zone. In order to reduce the multisolution of opening fracture identification in noncoring section, this study calculated the rock mechanics parameter curve through logging curve and summarized the rock mechanics parameter characteristics of opening fracture zone development section. The rock mechanic parameter mainly reflects the properties of rock skeleton, while the logging curve mainly reflects the properties of fluid in the rock. The combination
of conventional logging and rock mechanics parameters can reflect the overall characteristics of formation skeleton particles and fluids, so as to identify the opening fractures more accurately.

The microscopic fractures were studied mainly by casting thin sections, and the internal details of the key microscopic fractures were observed with the aid of scanning electron microscope and cathodoluminescence. In this study, a random sampling method was used to count the microscopic fracture parameters. For each casting thin section, 9 fields of view were randomly selected to calculate the length, opening, and number of the fractures. The average method is used to measure the opening of each microscopic fracture. Three locations with different opening degrees are selected to measure the opening of the microscopic fracture, and then the average value is taken as the opening of the microscopic fracture.

The calculation methods of porosity and permeability of microfractures in tight sandstones are still currently in the exploratory stage. At present, there are two commonly used methods. Wang et al. [25] used the two parameters of fracture opening and fracture spacing to calculate the porosity and permeability of fractures. This method is relatively simple and convenient in terms of the statistics and calculation processes, but neither considers the relation between the apparent open degree of the fracture and the true open degree nor the length of the fracture. In light of this, another more reasonable calculation method was chosen as follows [26, 27]). It is possible to measure several opening values and then calculate their average values because the opening of microscopic fracture is uneven. The opening of the vertical and microscopic fractures is the actual opening of the microscopic fracture, and the actual flakes are not always perpendicular to the surface of the fracture. Therefore, it is necessary to correct the fracture opening measured under the microscope. The correction formulas are as follows [26, 27]:

\[ e = \frac{2}{\pi} \cdot \frac{1}{n} \sum_{i=1}^{n} e_i. \]  

(1)

\( e \) is the actual fracture width. \( e_i \) is the measured fracture width.

The formula for microscopic fracture porosity is as follows. [26, 27]:

\[ \varphi_f = \left( \frac{1}{A_s} \right) \sum_{i=1}^{n} L_i \cdot e_i. \]  

(2)

\( \varphi_f \) is the microscopic fracture porosity. \( A_s \) is the sample area. \( L_i \) is the microscopic fracture length. \( e_i \) is the fracture opening.

The formula for calculating microscopic fracture permeability is as follows. [26, 27]:

\[ K_f = C \cdot \frac{1}{A_s} \sum_{i=1}^{n} L_i \cdot e_i^3. \]  

(3)

C is the coefficient of proportionality, the study area is randomly distributed fractures. The value of C is \(1.71 \times 106\).

Although the Monte Carlo method has some limitations, for example, the estimates for the fracture porosity and permeability of the samples are associated with the ratio of the fracture space to the sample size, calculating the fracture porosity and permeability based on the Monte Carlo method can reflect the relative fracture porosity and permeability to some extent [28].
4. Results

4.1. Types and Characteristics of Macroscopic Fractures. The macroscopic fractures in the study area are divided into non-structural fractures, structural fractures, and artificially induced fractures. Nonstructural fractures include diagenetic fractures, abnormal high-pressure fractures, sedimentary fractures, and artificially induced fractures.

4.1.1. Nonstructural Fractures. The first type is developed at the junction of sandstone and mudstone, which is formed by compression dissolution under the strong compaction of the overlying strata. The fracture extension direction is mostly consistent with the lithologic interface, with small opening and discontinuity. The second type develops along the direction of bedding, which is also a pressure-dissolved fracture formed under the pressure of overlying strata. Such fractures are mainly developed where bedding is developed, especially at the bedding interface adjacent to sandstone and mudstone or sandstone and plastic cuttings. The opening degree and density of the fracture are small. The shape of the fracture surface is regular without associated fracture. The two types of fractures show intermittent dark stripes in imaging logs, indicating that the fractures are in a semiopen state, which is consistent with the core observation (Figures 2(a) and 2(b)).
(1) Gravel Shrinkage Fractures. The gravel shrinkage fracture refers to the tensile fracture formed during the shrinkage of the rock (Figure 2(j)). The study area is widely developed with mud. According to statistics, almost every gravel contains shrinkage fractures, which only develop inside the grave. The scale of gravel shrinkage fracture is small. The fracture surface is uneven and mostly distributed horizontally. Due to the compaction effect, these fractures have small opening. Although the gravel shrinkage fracture is the macroscopic fractures with the largest amount, it does not contribute to the reservoir physical property described today.

(2) Abnormal High-Pressure Fractures. The fractures associated with abnormal high pressure are typical tensile fractures, which are completely filled with carbon. These fractures develop in a disorderly manner such as filamentous lenticular and plate-like without fixed forms, generally with small inclination angle and near horizontal fractures. The opening is generally between 0.5 mm and 5 mm. The extension length is short, generally a few centimeters. This kind of fracture develops in some layers of the study area (Figures 2(d) and 2(k)). The fractures related to abnormal high pressure in the study area are nearly horizontal, reflecting that the stress states their formation are detailed as $\sigma_x \geq \sigma_y \geq \sigma_z$, where $\sigma_x$, $\sigma_y$, and $\sigma_z$ represent the principal stresses of the two horizontal directions and one vertical direction, respectively. The principal stress is parallel to the vertical direction. In the gently inclined formation, mechanical and hydraulic effects form abnormal high-pressure fractures with such characteristic fractures [27]. While the abnormal pressure fractures in the study area do not have obvious regularity, so it should be formed under hydraulic action. Due to the existence of pore fluid, the rock fracture strength is greatly reduced. When the pore fluid pressure is greater than the tensile strength of the rock, the chisel will produce a near-level tensile fracture under a certain stress state. When the fluid pressure is lowered, the fracture opening is reduced. During this process, precipitation is often accompanied, and a near-level vein is formed. According to the MDT logging pressure measurement and DST formation pressure measurement in the study area, the current formation pressure coefficient of the Huagang Formation in the study area is 1.01~1.03, which belongs to normal pressure. In addition, overpressure fractures are not universally developed, which inferred that overpressure seams are caused by local abnormal pressure. By observing and counting cores, imaging logs, and casting thin sections, it is found that most of the abnormal high-pressure fractures are developed in the glutenite layer. When strong calcite cemented layers are developed above and below the glutenite layer. Local storage boxes will be formed between the strong cemented layers. When the pressure on the overlying strata increases, it will produce overpressure (Figure 2(d)). At the same time, the glutenite layer has poor sorting performance, and the adhesion between the granules is weak. When the pressure rises, the glutenite layer is weakly bonded and fractures are firstly formed.

(3) Fractures Formed during Deposition. Fractures during deposition refer to the fractures formed prior to sediment handling sedimentation and incomplete consolidation, which generally do not have reservoir and seepage capabilities [29]. The first type is fractures in gravel. There are fractures in some gravels, which have no orientation and no obvious period. The fracture surface is straight, with mud-filled in the interior. Therefore, it is inferred that such fractures are mainly fractures formed by collision during the sediment transportation process (Figure 2(l)). The second type occurred before the rock is consolidated. At this time, the rock is in a plastic flow state, and after the fracture is generated, it is filled with plastic material in the rock (Figure 2(m)).

(4) Artificial Induced Fractures. During drilling, due to the induction of drilling tools and mud pressure, the formation pressure will be released along the direction of the current maximum principal stress, causing the weak surface around the wellbore to fracture and form artificial induced fractures. Induced fractures are the main interfering factors in the identification of fractures in imaging logs. A dual-track or "\(X\)" pattern parallel to the direction of the drill pipe is displayed on the imaging log [30]. The above two methods are distributed in the study area (Figures 2(c)–2(e)). The double-track type extends up to several tens of meters. The induced fracture is developed on a large scale in imaging logging, which is also the main reason for the unsatisfactory imaging logging effect of $X - 1$ well. The direction of the maximum principal stress in the study area is E-W direction by the artificially induced slit-to-rose diagram (Figure 3).

4.1.2. Structural Fractures. Whether in the extensional structure zone, the extrusion zone, or the stable zone, tectonic shear fractures are the most widely developed fracture genes, which are often characterized by high-angle shear fractures [31]. Affected by some factors such as weak mudstone layers, there may also be low-angle shear fractures that do not meet the rock shear fracture criterion [27]. The structural fractures are widely distributed in various lithologies. The low-angle fractures often appear in groups, and the high-angle fractures are often affected by the dip angle, appearing as a single fracture, which has obvious directionality. Mineral fillings are often found in fractures. The smaller the fracture dip, the more severe the filling is. Low-angle slip fractures are often formed in silty mudstones and mudstones due to structural compression, which have obvious scratches and mirror features along the fracture tendency (Figure 2(n)). The fractures have various shapes and small openings, most of which are less than 0.5 mm. According to the FMI imaging log statistics, there are two main combinations of structural shear fractures: the first is parallel (including a single fracture) (Figures 2(e) and 2(f)). This kind of fracture is composed of multiple parallel sinusoidal combinations with similar morphology, which is common in the study area. The other is conjugate. It is a combination of two sets of opposite sinusoidal curves, which is a conjugate shear fracture formed under the structural compression stress. The conjugate shear fractures on
FMI imaging logs are often broken on the core, which indicates that the density of conjugate fractures leads to weak rock cohesion (Figure 2(g)).

4.2. Types and Characteristics of Microscopic Fractures. The microfractures in the study area are mainly divided into physical genetic fractures and chemical genetic fractures. Physical genetic fractures include wear-particle fractures, internal fractures in mineral grains, grain edge fractures, mud shrinkage fractures, and mica cleavage fractures. Chemical genetic fractures include feldspar cleavage dissolution fractures and pressure-soluble fractures.

4.2.1. Fractures of Physical Origins

(1) Transgranular Fractures. As in the case of macroscopic fractures, the causes of transgranular fractures are complex; they may have many geneses such as tectonics, diagenesis, and abnormally high pressure. Their characteristics are similar to those of the same type of macroscopic fractures [32]. The transgranular fractures are the microscopic fractures with the largest scale, the longest extension, and the largest openings. They are not restricted by mineral particles and can usually pass through multiple mineral particles (Figures 4(a)–4(c)). There are relatively few transgranular fractures in the study area, and they mainly comprise structural fractures with relatively small scale; the trailing ends of the fractures typically show tails and bifurcation. The fracture openness does not vary considerably, only becoming small and sharp at the ending. Under scanning electron microscopy, the seam surfaces often show secondary changes, such as dissolution and clay mineral cementation. Some large-scale granules are accompanied by smaller grain-edge fractures and transgranular fractures. At the same time, because of the high permeability of the transgranular fractures, there is strong dissolution near them, which is conducive to the development of dissolution fractures (Figure 4(a)).

(2) Intragranular Pressure Fractures. Intragranular pressure fractures develop when mineral particles are subjected to overlying gravity or structural stress greater than their fracture strength [33]. The intragranular pressure fractures in the study area consist of completely split fractures and partially split fractures according to the degree of fracturing. Completely split fractures form when the mineral particles break into two or more parts, the different ends of which are often connected with different pores. Some fractures formed in a “V” shape (Figure 4(d)). The intragranular pressure fractures in mineral grains are mostly open, with clean fracture surfaces. The degree of fracture opening is mainly controlled by the movable space around the ruptured particles and the strength of later dissolution (Figures 4(d)–4(f)). The internal pressure fractures in feldspar grains are often affected by dissolution in later stages, which further increases the degree of opening of the fractures or the dissolution holes. Because the fracturability of the weaker surfaces of feldspar grains is greater than that of quartz grains, feldspar particles developed multiple intragranular fractures, whereas quartz particles in the same samples had fewer intragranular fractures (Figure 4(d)). A small amount of intragranular fractures in quartz grains were also affected by erosion, but the extent and amount of dissolution were much smaller than those of feldspar grains.

(3) Other Fractures. Grain edge fractures are mainly distributed between mineral particles and along the edges of...
mineral particles. Therefore, they are often referred to as intergranular or agglomerated fractures [27]. The grain edge fractures in the study area mainly developed in the glutenite interval, because of the weak cementation between gravel particles. When stress is applied, grain edge fractures are generated around gravel particles. The openings of fractures of this type are generally large, second only to the openings of transgranular fractures (Figure 4(g)).

**Figure 4:** Microfracture types of the Huagang Formation in the Xihu Depression. (a) Transgranular fractures. There are many derivative secondary fractures distributed around them (well X2, depth 3600.5 m). (b and c) The transgranular fracture shows good connectivity, with a small amount of siliceous cement (well X2, depth 4020.3 m). (d) Nos. 1–2 are intragranular fractures in a quartz grain, the surfaces of which are clean and show no postcorrosion phenomenon. Nos. 3–7 are the intragranular fractures of a feldspar grain. The same feldspar particle developed multiple intragranular fractures, some of which expanded significantly during later-stage dissolution. No. 8 is a feldspar cleavage dissolution fracture (well X1, depth 3716.1 m). (e) Intragranular fracture of a quartz grain with a clean fracture surface (well X3, depth 4000.3 m). (f) Intragranular fracture of a feldspar grain-filled by later chlorite (well X2, depth 3720.9 m). (g) The periphery of the gravel grain split into a grain edge fracture under stress, and some of this fracture was filled with later iron-bearing calcite (well X2, depth 3890.0 m). (h) Inside the mud debris, a split formed slits along the direction in which the debris spread (well X2, depth 3896.2 m). (i) Muscovite cleavage planes that formed fractures under stress (well X2, depth 3996.2 m). (j) In the dense reservoir, mineral particles were eroded at the contact edges of particles because of strong compaction, forming wavy pressure-dissolution cleavage (well X2, depth 4080.5 m). (k) The quartz particles underwent small-scale dissolution to form a fracture (well X2, depth 4000.3 m). (l) Transgranular fracture cemented by later mud and plastic material was compacted into a linear shape (well X2, depth 4012.4 m).
Mud debris shrinkage fractures generally form by fracturing along the long axes of mud debris. The fractures are curved, with long and sometimes intermittent extents (Figure 4(h)). Mica cleavage fractures are mostly formed by the displacement of mica cleavage subjected to stress and have the same curved shapes as the mica particles and narrow fracture surfaces (Figure 4(i)).

4.2.2. Chemical Fractures

(1) Pressolution Fractures. Pressolution fractures are mainly distributed between mineral particles and, thus, are a type of grain edge fracture. Fractures of this type are mostly related to strong mechanical compaction and pressure-melting effects, and some form by corrosion [27]. Such fractures have small openings, generally smaller than 5 μm. The fracture surfaces are not clean, and fractures can develop between adjacent particles or on multiple side-by-side particles (Figure 4(j)).

(2) Dissolution Fracture. The dissolution fractures are mostly dissolution fractures within the feldspar grains, especially the dissolution fractures developed along the feldspar crystal grains. The dissolution fractures along the feldspar crystal grains are generally clean, which in other directions are generally semicorroded, with irregular surface, and residual corrosion inside (Figure 4(a)). There are also some plastic minerals, granules within the granules, and a small amount of intragranular erosive fractures (Figure 4(k)).

4.2.3. Implicit Fractures. Implicit fractures can be defined in terms of static and dynamic. In static state, fractures smaller than the crystal size are called concealed fractures, that is, fractures that are not visible under the optical microscope. Fractures of this type are called implicit fractures. In dynamic state, the explicit fracture, which is filled after late diagenetic cementation action, is called an implicit fracture too [34]. In this paper, the linear and strip-shaped mechanical weak surface with no openness is also called implicit fracture in the size of the optical microscope.

Filled fractures have the most content in the study area (Figure 4(l)). The three types of microscopic fractures described above are all heavily filled. With a large number of intramendullary fractures and grain margin fractures, the corresponding filled hidden fractures are also the largest number of hidden fractures. The second type of hidden fractures is sedimentary structures related to sedimentation. Plastic materials such as plastic minerals and mud debris are distributed in a stripe shape under the effect of overpressure after deposition. Although they form a whole with the surrounding minerals, these plastic bands are more likely to break and form fractures when subjected to external forces.

5. Discussion

5.1. Controlling Factors of Macroscopic Structural Fracture Distribution

5.1.1. Formation Mechanism of Macroscopic Structural Fractures. The Xihu Depression experienced three major tectonic movements (Figure 1). The rifting period was mainly affected by the tensile stress in the NW-SE direction. At this time, there was no deposition of the Huagang Formation in the target layer, so the current tectonic movement did not play a role in the fractures of the Huagang Formation. After entering the reversal period, the Philippine Plate subducted below the Eurasian Plate, producing left-hand compression along the Diaoyu Island fold belt and the right-hand movement of the southwestern Japanese Island Arc and the Yushan-Kumi Fault, which collectively squeezed westward to trigger Longjing Movement. Under this background condition, the central uplift belt forms a large northnorth-east oriented anticline, the two wings of which develop north-east-east and north-east oriented reverse faults and a few small north-west and north-northwest normal faults Liu [35]. Affected by the above, the study area mainly developed conjugate shear fractures with north-north-east direction. At the same time, affected by the current principal stress, imaging logs show that a large number of east-west induced fractures have been developed in the target layer, which are aligned with the current principal stress direction (Figure 3).
reason for the large number of fractures in the H1 Formation than in the H2 Formation.

$$E = \frac{\rho}{D T_s^2 - 4 D T_p^2} \times 10^6,$$

$$\nu = \frac{D T_s^2 - 2 D T_p^2}{2(D T_s^2 - D T_p^2)},$$

$$B L_E = \frac{E - E_{\text{min}}}{E_{\text{max}} - E_{\text{min}}},$$

$$B L_v = \frac{\nu - \nu_{\text{max}}}{\nu_{\text{min}} - \nu_{\text{max}}}$$

$$B I = \frac{B L_E + B L_v}{2} \times 100\%.$$

$E$ is Young’s modulus, GPa. $\nu$ is the rock Poisson’s ratio with dimensionless. Subscripts min and max represent the maximum and minimum values of the parameter in a certain formation. $\rho$ is the volume density, g/cm$^3$. $D T_s$ is the longitudinal wave time difference, $\mu$s/m. $D T_p$ is the shear wave time difference, $\mu$s/m. 106 is Young’s modulus converted to the coefficient in GPa. $B I$ is the brittleness index, %. $B L_E$ and $B L_v$ are, respectively, passed the brittleness index calculated by Young’s modulus and Poisson’s ratio.

5.1.3. Different Parts of the Fault Have Different Control over the Macroscopic Structural Fractures. The faults that penetrate the target layer in the study area are mainly distributed in the two wings of the anticline. Wells X-1, X-2, X-4, and X-3 are from near to far from the fault. The number of macroscopic fractures is counted by imaging logs and cores. The number of fractures in well X-4 cannot be counted due to its short coring and lack of well logging. The imaging quality of X-1 well imaging logging is not good, so fracture statistics are not reliable. The X-2 well is significantly more numerous than the X-3 well (Figure 6), mainly because well X-2 is significantly closer to the fault than well X-3, especially closer to the end of the fault. Previous studies have shown that the closer to the fault, the greater the number of fractures. A large number of radial secondary faults or fractures often develop at the tip of the fault or fracture. The above two reasons may be the reason that the fracture density of well X-2 is much larger than that of well X-3.

5.1.4. Obvious Correlation between Rock Thickness and Macroscopic Structural Fracture Density. From the inside of the H1 Formation, the fracture density has a good negative correlation with the single layer thickness of the rock (Figure 7), which indicates that thickness is one of the important factors affecting the development of structural fractures in the target layer in the same interval.

5.1.5. Sedimentation Is the Basis of Macroscopic Structural Fractures. The lithofacies of the study area are obviously controlled by sedimentary microfacies, so the distribution of fractures in different waterway types also has obvious regularity. The low-energy braided channel is dominated by medium-fine sandstone, so the fracture density is the largest (1.71/m), followed by the gravel-like waterway (1.23/m), and the high-energy braided channel has the lowest fracture line density (1.05/m) (Figure 8).

At the same time, due to the difference of sedimentation, the number of different types of lithology in the study area is significantly different, which also leads to different
distribution probability of fractures in different types of lithology (Figure 9).

5.2. Controlling Factors of Microscopic Fractures. It is found that the wear-particle fractures are accompanied by macroscopic fractures, which indicate that the wear-particle fractures are mainly controlled by the stress field. However, existing data in the study area show that there are few wear-particle fractures, so we do not explain too much about the factors that control wear-particle fractures.

It is found that the intragranular pressure fracture is affected by many factors. In addition to being affected by the tectonic stress field, the degree of cementation, particle contact relationship, and equal deposition all have an effect on its distribution.

When the basal carbonate cementation is developed, the mineral particles are substantially free of intragranular pressure fractures due to the protection of the carbonate cement. The particle contact relationship in the Huagang Formation was developed from floating to suture contact, and the floating and point contact were basically free of intragranular pressure fractures. When the point-line contact occurs, the intragranular pressure fracture begins to appear. The intragranular pressure fracture is most developed in the line and line-convex contact stages. At the suture contact stage, the preformed microscopic fracture will be compacted with the densification of the reservoir (Figure 10). The sedimentary facies of the Huagang Formation is braided river delta. The reservoir was mainly developed in the braided water channel. It was found that the intragranular pressure fractures in the high-energy braided water channel were significantly more than those in the low-energy braided water channel. This is mainly because low-energy braided channels have weak hydrodynamic forces and high contents of plastic components such as argillaceous matrices, which can buffer the stress of rigid minerals, when they are squeezed by stress.

In this study, the opening orientation of microscopic fractures could not be determined due to the lack of directional treatment of the casting thin section. However, it was found that the intragranular pressure fracture was not significantly oriented in the same casting thin section (Figure 4(d)), which was significantly different from the macroscopic fracture. The reason is analyzed using a simplified schematic diagram in this study (Figure 11). Mineral burst occurs when the resultant force of a weak surface is greater than the fracture strength of this surface, which is affected by many factors. First, different mineral particles have different stresses in the same sample. The stress on each mineral particle is affected by many factors. Although the gravity field...
Figure 11: Formation mechanism of a pressure fracture in a grain. \( G \) is gravity; \( F \) is the regional structural principal stress; \( f \) is the point compressive stress, and \( g \) is the frictional force. The particle distribution in the rock formation is simplified to a planar model. The figure shows the force model, when the particles are in point contact. As the depth of burial increases, the particles are oriented. Gravity and regional tectonic stress are regarded as the first and second principal stresses. Particle No. 1, the mechanically weak surface of which is parallel to the direction of gravity, is most likely to be broken. Particle No. 2 will be squeezed by the friction of the upper particles and form the friction \( g \) under the isocline. With the increase of gravity parallel to the direction of gravity, it is most likely to be broken. Particle No. 2 will be squeezed by the friction of the upper particles and form the friction \( g \) under the isocline. With the increase of gravity, it is most likely to be broken.

Particle No. 2 will be squeezed by the friction of the upper particles and form the friction \( g \) under the isocline. With the increase of gravity parallel to the direction of gravity, it is most likely to be broken. Particle No. 2 will be squeezed by the friction of the upper particles and form the friction \( g \) under the isocline. With the increase of gravity, it is most likely to be broken.

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two main periods of hydrocarbon charging (Figure 12). The first stage was in the period of rapid tectonic uplift. At this time, the Huagang Formation had entered the middle diagenetic stage B, and the reservoir had been gradually densified. The open fault-fracture system provided an important channel for oil and gas migration. Although the sizes of the inclusions were too small (Figure 13) to measure the homogenization temperature, they were sufficient to show that the fractures previously served as migration channels for oil and gas in the filling period.

The fault-fracture system, as it provided migration channels for oil and gas, also brought acidic fluids, which generated conditions for the dissolution of surrounding minerals. When the fault layer broke through the caprock, the fault-fracture system would provide an open dissolution environment for the nearby rocks and remove the dissolution products over time, thus, promoting dissolution. Observations of the casting thin sections around the open macroscopic structural fractures revealed that structural transgranular fractures were relatively well developed near the open macroscopic structural fractures, and large numbers of secondary microscopic fractures and dissolution pores were developed around the transgranular fractures (Figure 4(a)). In other low-permeability and tight reservoirs in the study area, dissolution was weak, with small numbers of dissolution pores and incomplete dissolution. The fracture-pore system not only promoted hydrocarbon accumulation but also was the main reservoir and seepage system of the tight sandstone gas reservoir.

5.3.2. Fracture Effectiveness and Its Influence on the Present Reservoir. The permeability in the study area ranges from $0.02 \times 10^{-3} \, \mu m^2$ to $850 \times 10^{-3} \, \mu m^2$. According to statistics, the density of microscopic fracture surfaces is basically less than $0.006 \times 10^{-3} \, \mu m^2$, and most microscopic fracture permeability measurements are less than $2 \times 10^{-3} \, \mu m^2$. When the sample permeability is larger than $2 \times 10^{-3} \, \mu m^2$, especially when it is larger than $10 \times 10^{-3} \, \mu m^2$, there is no correlation between the microscopic fracture permeability and the sample permeability, which indicates that the main seepage channels of the sample are pore throats, whereas microscopic fractures play a small role. For low-permeability and tight reservoirs, the permeability generated by microscopic fractures is an important part of reservoir permeability. Fracture
surface density and fracture permeability have strong positive linear correlations with the overall sample permeability (Figure 14) when the sample permeability is less than $10 \times 10^{-3} \mu m^2$. However, the permeability of microscopic fractures is limited. Only in a few samples with well-developed transgranular fractures is the permeability of microscopic fractures greater than $1 \times 10^{-3} \mu m^2$. The above shows that microscopic fractures are an important part of the matrix permeability of tight reservoirs; they can improve matrix permeability within a certain range, but cannot change the order of magnitude of reservoir permeability. Thus, relying only on microscopic fractures is insufficient to form natural productivity. This is also important evidence for the above viewpoint that there is no obvious natural productivity increase in the section with microscopic fracture development compared with other layers.

The opening macroscopic fracture permeability is several orders of magnitude larger than the matrix permeability Zeng et al. [27]. As mentioned above, there are numerous fractures in the study area, but only about 10% of them were found to be effective fractures based on statistical analysis. Gas testing was carried out in several tight formations where the logging interpretation results indicated the presence of gas reservoirs. The results show that natural gas flow with industrial development value appeared in the fracture development zones of macrostructural openings in the two sections, and that the natural productivity of other intervals was very small, which indicates that macrostructural opening fractures may be key to the formation of natural productivity of tight reservoirs.

6. Conclusions

(1) The identification methods for different types of fractures are different. Core is the most direct method to open macrofracture observation. The fracture opening in noncore section needs comprehensive analysis of various means. Imaging logging can better display low angle and medium angle fracture, and high angle fracture, especially the open high angle joint, is affected by induced fracture, and the imaging logging has a poor display effect on it.

(2) The occurrence of macroscopic structural fractures in tight sandstone reservoirs has obvious regularity. The fracture strike is mainly controlled by the tectonic stress field. In addition to the structural stress field, the depth, lithology, rock thickness, sedimentary microfacies, and faults also control the dip angles, sizes, and density of fractures. Transgranular fractures are basically associated with macroscopic structural fractures. There is no obvious regularity in the distribution of intragranular fractures, which is mainly attributed to the inhomogeneity of mineral particles in mechanically weak planes, their shapes, and other particles in contact with them. In addition,
grain contact relationships, sedimentary microfacies, and early cementation are also important factors controlling the development of microscopic fractures.

(3) Effective fractures provide channels for the migration of oil and gas and acidic fluids in the historical period, which promote the occurrence of hydrocarbon accumulation and dissolution. At present, effective macroscopic fractures are key to the natural productivity of tight reservoirs. The strength of cementation in fractures is key to controlling the effectiveness of fractures, which is mainly controlled by the fracture dip angles. Microscopic fractures can improve the permeability of the reservoir matrix in a certain range, but they cannot change the order of magnitude of reservoir permeability.

(4) There are fracture reservoirs in the Huagang Formation of the Xihu Depression. Effective macroscopic structural fractures, microscopic fractures, and dissolution pores constitute the tight reservoir permeability system of the Huagang Formation. The effective macroscopic fractures are mainly open structural fractures, most of which were filled by carbonate cement in the stable settlement period. Microscopic fractures are mainly intragranular fractures, among which feldspar grain intragranular fractures are dominant.

Data Availability

The data required in this article have been shown in the figures and tables.

Conflicts of Interest

The authors declare that they have no conflicts of interest.

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