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Shale Oil Reservoir Characteristics and Enrichment in the Jiyang Depression, Bohai Bay Basin, East China

Yongshi Wang[1], **Chao Liang***[2], **Xinian Sun**[1]
1. *Geological Scientific Research Intitute*, *SINOPEC Shengli Oilfield*, *Dongying* 257015, *China*
2. *School of Geosciences*, *China University of Petroleum*, *Qingdao* 266000, *China*
Yongshi Wang: http://orcid.org/0000-0002-7851-1623; Chao Liang: http://orcid.org/0000-0002-9941-6983

ABSTRACT: Based on the observation of the well cores, thin section and FESEM, combined with X-ray diffraction, physical property testing and geochemical indicators, the reservoir characteristics and the controlling factors of the shale oil enrichment of the $\mathrm{E}s_4^{s}$–$\mathrm{E}s_3^{x}$ shale in the Jiyang depression were detailed analyzed. Studies show that carbonate and clay minerals are dominated in the shale. According to the triangle chart, the TOC content (2% and 4%), carbonate and clay minerals, nine lithofacies have been identified. The reservoir space types are rich in the shale, in which, the laminated fractures, recrystallization intracrystalline pores and organic pores are high-quality reservoir spaces. The shale oil enrichment is mainly determined by the hydrocarbon-producing potential and reservoir capacity. The hydrocarbon-producing capacity is controlled by the organic geochemistry indicators, especially the TOC content for the study area, and the thickness of the organic-rich shale. The reservoir capacity is mainly affected by the lithofacies, the TOC content and the structural activities. In addition, the shale oil production is influenced by the fracability of the shale, which is mainly controlled by the lithofacies, structural activities, formation pressure, etc. The shale oil reservoir evaluation should focus on the TOC content, the thickness of the organic-rich shale, lithofacies and structural factor.

KEY WORDS: shale oil, reservoir characteristics, enrichment factors, Jiyang depression.

0 INTRODUCTION

Currently, the exploration and development for marine shale gas has formed a relatively complete theory, methods and technology system (Pan et al., 2015; Dong et al., 2012; Zhang et al., 2012a; Zheng et al., 2011). While the lacustrine shale oil has not yet formed large production, although has several small discoveries in many basins (Liang et al., 2017a; Yang H et al., 2013; Zou et al., 2013). According to preliminary data statistics, the lacustrine shale oil has large resource potential, with resource quantity up to 130 billion tons, while the reservoir formation mechanism and evaluation technology have not yet formed. There are many differences between lacustrine and marine shale in sedimentary environment, mineral composition, source rock characteristics and reservoir pore space (Li et al., 2016; Liang et al., 2016; Chen et al., 2009; Wang et al., 2009), which suggests that the exploration and development theories of lacustrine shale need further improvement, methods and technology system on the domestic shale oil research should be improved with more pertinence.

There are many Cenozoic lacustrine basins widely distributed in Central and East China, in which the organic rich lacustrine shales are well developed (Jiang et al., 2014; Zhang et al., 2012b). What's more, there are many similarities between different basins, thus the research of shale oil enrichment in the typical basin has extensive promotional value.

The study of reservoir characteristics is very important for shale oil. The reservoir pore space in the shales includes 4 categories: (1) interparticle pores, (2) intraparticle pores, (3) organic pores, and (4) fractures, and all of these can provide the storage space for shale oil (Loucks et al., 2012; Slatt and O'Brien, 2011). The development of pores network depends on mineral composition, occurrence, TOC content and diagenesis. The TOC content and organic matter types are the key to the development of organic pores (Yu, 2013; Loucks et al., 2012). The domestic scholars have carried out many researches on the reservoir pore space formation and evolution in the lacustrine shale (Liang et al., 2017b; Wang et al., 2013; Yang F et al., 2013; Deng and Liang, 2012), and proposed shale oil reservoir evaluation and resource assessment methods. The TOC content, organic matter thermal maturity, organic-rich shale thickness, reservoir physical properties, oil-bearing ability, shale oil viscosity, burial depth and formation pressure are important considerations for shale oil evaluation (Jiang et al., 2014; Zou et al., 2013; Zhang et al., 2012a). Song et al. (2013) and Wang et al. (2013) proposed the evaluation methods and calculated the resource quantity of shale oil reservoir in Jiyang depression. Currently, several wells have gained commercial oil flow and many wells have oil and gas shows in the shale intervals, which fully demonstrates the great potential for shale oil exploration in Jiyang depression (Wang et al., 2013).

*Corresponding author: liangchao0318@163.com

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Based on the well cores, observation of thin sections and field emission scanning electron microscope (FE-SEM), X-ray diffraction, physical property testing and geochemical indicators from several cored wells in the Jiyang depression, the petrology, reservoir pore space of the Es_4^s–Es_3^x shale have been detailed studied. In this paper, we also discuss the controlling factors of shale oil enrichment, including the hydrocarbon generation conditions, reservoir capacity and reservoir fracturing, which will provide some guidance and references for the shale oil exploration in Jiyang depression.

1 GEOLOGICAL SETTING

The Jiyang depression is a typical Mesozoic–Cenozoic rift depression located in the southeast of the Bohai Bay Basin, which is bordered by the Tanlu fault belt in the east, Chengning uplift area in the northwest, and Luxi uplift in the south (Zhu et al., 2013; Qiu et al., 2006). The Jiyang depression includes four secondary depressions: Dongying depression, Huimin depression, Zhanhua depression and Chenzhen depression, which are divided by Qingcheng uplift, Chenjiazhuang uplift and Yihezhuang uplift (Fig. 1a). The Jiyang depression has experienced three tectonic stages, and is in depression period during the Early Eocene (Zuo et al., 2015; Zhu et al., 2013; Li et al., 2007; Wang et al., 2002). Relatively stable tectonic movement, deepened lake water, warm-humid climate and terrigenous nutrients enrichment in the Es_4^s–Es_3^x conductive to the organism bloom (Fig. 1b) (Huang et al., 2015; Wang Y S et al., 2013; Wang Y et al., 2002). Under the sedimentary background, thick Es_4^s–Es_3^x organic rich shale is well developed, with high carbonate minerals content, stable thickness and moderate depth.

2 METHODOLOGY

This study utilizes a comprehensive theory that integrates sedimentology, reservoir geology and petroleum geoscience, by which the reservoir characteristics and the controlling factors of the shale oil enrichment were detailed analyzed. The basic data includes a total of 1 000 m cores and 1 200 thin sections from 5 wells (L69, NY1, LY1, F120 and FY1, Fig. 1a), 249 field emission scanning electron microscope (FESEM) samples, rock pyrolysis analysis, maceral composition and organic carbon data from 500 samples, and X-ray diffraction data from 1 200 samples. The thin sections observations were taken using a Zeiss microscope Axio Scope A1, and samples were prepared with a thickness of 0.03 mm. The mineral X-ray diffraction was performed using a D/max-2500 TTR. The organic carbon content was determined using a Leco carbon-sulfur analyzer CS600 and gas-shows evaluation instrument, and the test temperature was 25 °C. The asphalt extraction was done before pyrolysis, and the Rock-Eval parameters measured included S_1, S_2 and T_{max}. Ar-ion-beam milling was used to prepare samples for imaging nanopores by high-resolution field emission scanning electron microscopy (FESEM). The samples were gold-coated and observed using a HITACHI S-4800 with a working current set at 10 kV.

3 MINERALOGY AND LITHOFACIES

3.1 Mineralogy

The Es_4^s–Es_3^x shale of Jiyang depression predominately consists of calcite, clay minerals and quartz, with subordinate plagioclase, potassium feldspar, anhydrite, pyrite and organic matters (Table 1). Studies show that the calcite is the dominant mineral, with an average of 42.26%, partly interval up to 70%. The calcite occurs as three manners: micritic, granular and columnar crystals, with a small amount of calcareous biological debris, such as ostracod fragments and calcispheres. The average content of quartz is 21.76 wt.%, with two forms: terrigenous debris particles and microcrystalline quartz, which is smaller than 10 μm and surrounded by clay minerals. The average content of clay minerals is 20.12 wt.%. Clay minerals are dominantly illite in the Dongying depression and illite-smectite mixed layer in Zhanhua depression. The pyrite mainly occurs as framboidal pyrite, with a size of approximately 5–20 μm, surrounded by clay minerals. The TOC content ranges from 0.5% to 14%, with an average of 2.51%. The organic matter is mainly planktonic algaes, enriched into layers, intermittent or isolated distributed in the shale.

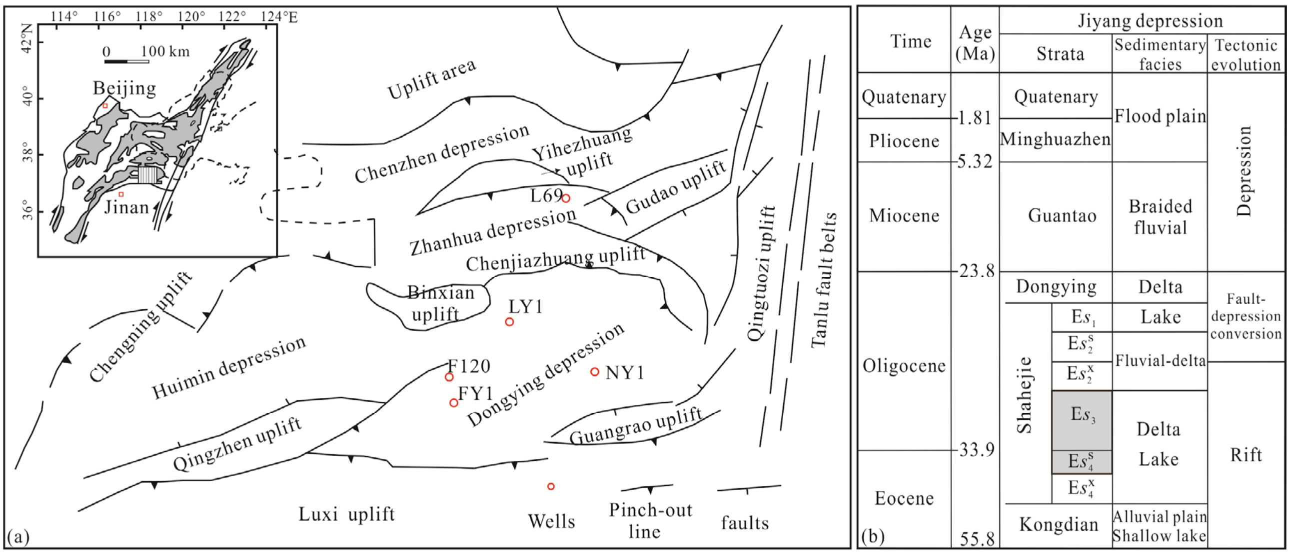

Figure 1. The regional structural map of Jiyang depression and the wells locations.

Table 1 Mineral content (wt.%) of the Es_4^s–Es_3^x shale in Jiyang depression

Wells (samples)	Interval (m)	Calcite	Quartz	Dolomite	Feldspar	Pyrite	Clay	Illite	I/S	TOC
L69 (877)	2 910–3 130	52.07	18.05	5.85	2.66	3.85	18.86	29.62	62.13	2.90
L67 (59)	3 162–3 300	52.81	18.35	6.13	2.26	4.13	17.29	48.05	45.64	2.19
NY1 (762)	3 295–3 500	35.28	22.85	13.12	6.17	2.98	22.17	83.46	15.44	2.72
FY1 (276)	3 051–3 451	37.58	24.47	13.57	8.06	2.84	16.45	87.46	11.16	2.20
LY1 (268)	3 736–3 835/3 581–3 700	33.57	25.07	8.71	4.82	2.94	25.82	77.29	19.71	2.56
Average		42.26	21.76	9.48	4.79	3.35	20.12	65.18	30.82	2.51

The illite and I/S content indicate the ratio in the clay minerals.

3.2 Lithofacies

Studies suggest that the TOC content is closely related to the shale oil yield and the reservoir properties (including calcite crystallinity, porosity, permeability and fracture development), and the sharp boundaries are 2% and 4% (Jiang et al., 2013). Therefore, the TOC content is considered and TOC 2% and 4% are used in the lithofacies classification. According to the mineral composition of the Es_4^s–Es_3^x shale, the paper proposed the lithofacies classification: first on the basis of TOC content, the fine-grained rocks are divided into three broad class, that are low organic (TOC<2%), middle organic (2%<TOC<4%) and high organic (TOC>4%) ones. Furthermore, according to the carbonate and clay minerals content, nine lithofacies have been identified: (1) high organic laminated limestone, (2) middle organic laminated limestone, (3) low organic laminated limestone, (4) high organic laminated claystone, (5) low organic laminated gypsum claystone, (6) low organic laminated dolomite claystone, (7) laminated silty claystone, (8) low organic massive marl, and (9) low organic massive claystone.

3.2.1 High organic laminated limestone (HLL)

The lithofacies is characterized by high TOC (>4%) and carbonate content (up to 80 wt.%), while clay minerals and terrigenous silts are rare. The light lamina is mainly composed of recrystallization calcite, which mainly occur as "needle" or grain crystal closely packed. The dark lamina is organic rich clay laminae (Figs. 2a, 3a).

3.2.2 Middle organic laminated limestone (MLL)

The carbonate content is more than 50%, and the TOC content ranges from 2% to 4%. The lithofacies is laminated: the light lamina is micritic calcite, partly recrystallize along the calcite laminae boundaries, and the dark lamina is mainly organic rich clay laminae (Figs. 2b, 3b).

3.2.3 Low organic laminated limestone (LLL)

The lithofacies is characterized by shallow gray color, high carbonate content (up to 70%) and low TOC content (less than 2%). The lamina is well developed and horizontal or wavy distributed. The light lamina is micrite calcite and dark lamina rich in clay minerals (Figs. 2c, 3c).

3.2.4 High organic laminated claystone (HLC)

The lithofacies is laminated with black color (Fig. 2d). The lithofacies has high clay minerals content, which is greater than 50%, with subordinate quartz and feldspar. The TOC content is more than 4%, with the organic matters enriched in layer (Fig. 3d).

3.2.5 Low organic laminated gypsum claystone (LLGC)

The lithofacies is gray colored. The anhydrite content ranges from 25% to 50%, which may be symbiotic with dolomite, and the clay minerals content is more than 50%. The lithofacies interval has a total 8.5 m thickness in the Es_4^s of Well NY1 (Figs. 2e, 3e).

3.2.6 Low organic laminated dolomite claystone (LLDC)

The lithofacies is mainly developed in the Es_4^s shale with gray and shallow gray color (Fig. 2f). The dolomite content ranges from 25% to 50%, which mainly occurs as micrite (Fig. 3f).

3.2.7 Laminated silty claystone (LSC)

The laminated silty claystone is gray and shallow gray colored (Fig. 2g) and plant fragments are common in the cores. The lithofacies has high terrigenous debris content and rich in ostracods fragments, with quartz content ranging from 30% to 35%. The organic matters dispersed distributed in the shale (Fig. 3g).

3.2.8 Low organic massive marl (LMM)

The lithofacies is massive and has high calcite content. The calcite is mainly micritic, which is mixed distributed with clay minerals. Ostracod fragments and terrigenous silts are common in the massive marl, indicating a relatively shallow water, with certain turbulent sedimentary environment.

3.2.9 Low organic massive claystone (LMC)

This lithofacies is gray/blue-gray and massive in well cores (Fig. 2i). The XRD-ray shows that the clay minerals content is more than 50%, with subordinate calcite and quartz. This lithofacies has low TOC content, lower than 1% (Fig. 3i).

4 RESERVOIR PORE SPACE AND RESERVOIR PHYSICAL PROPERTIES

4.1 Reservoir Pore Space

Based on well cores and thin sections observation, combined with Ar-ion polishing and FESEM observation, the reservoir pore space are detailed analyzed. The reservoir pore space in the Es_4^s–Es_3^x shale include organic pores, inorganic pores and fractures.

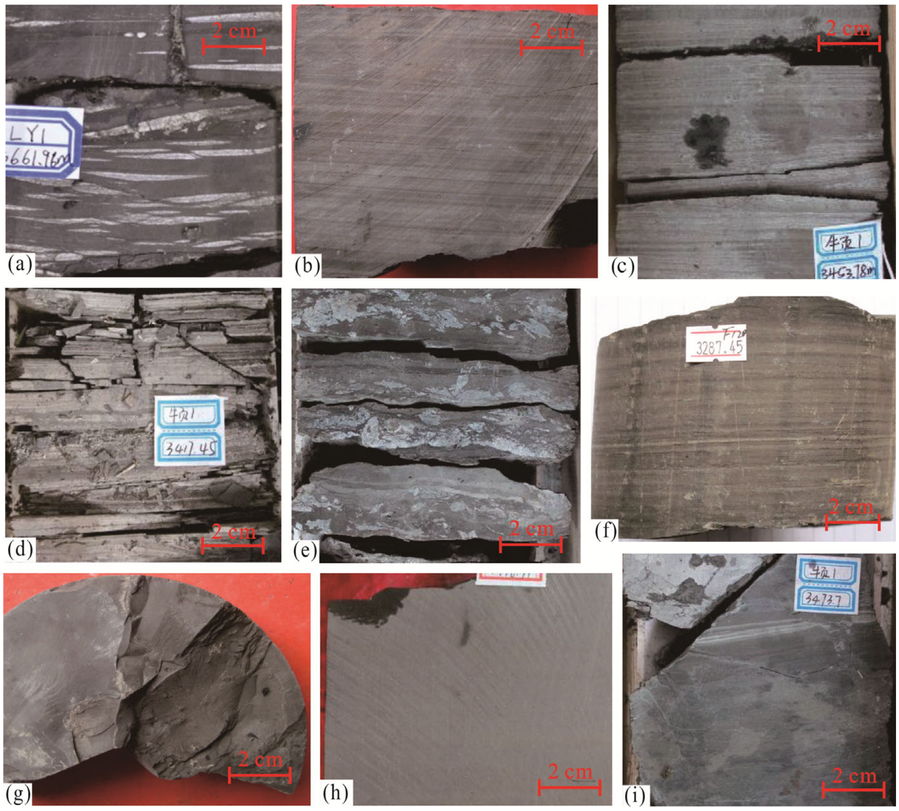

Figure 2. The macro characteristics of lithofaces in the Es_4^s–Es_3^x shale. (a) High organic laminated limestone, Well LY1, 3 661.96 m; (b) middle organic laminated limestone, Well L67, 3 270.1 m; (c) low organic laminated limestone, Well NY1, 3 453.78 m; (d) high organic laminated claystone, Well NY1, 3 417.45 m; (e) laminated gypsum claystone, Well NY1, 3 492.08 m; (f) laminated dolomite claystone, Well F120, 3 287.45 m; (g) laminated silty claystone, Well L67, 3 250 m; (h) low organic massive marl, Well L69, 2 996.71 m; (i) low organic grey-blue massive claystone, Well NY1, 3 473.7 m.

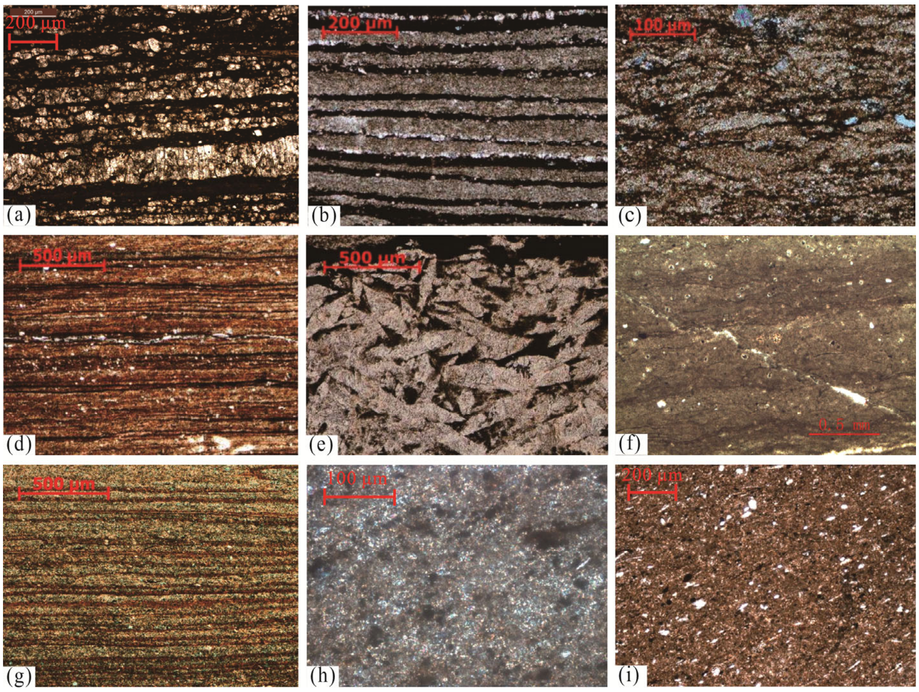

Figure 3. The micro characteristics of lithofacies in the Es_4^s–Es_3^x shale. (a) High organic laminated limestone, Well W584, 3 610 m; (b) middle organic laminated limestone, Well NY1, 3 302.34 m; (c) low organic laminated limestone, Well FY1, 3 211.78 m; (d) high organic laminated claystone, Well NY1, 3 374.39 m; (e) low organic laminated gypsum claystone, Well NY1, 3 492.5 m; (f) laminated dolomite claystone, Well L673, 4 040.6 m; (g) silty claystone, Well N30, 2 905 m; (h) massive mudstone, Well L69, 2 958.81 m; (i) massive mudstone, Well L69, 2 953.35 m.

The organic pores refer to the matrix pores related to the organic matters, which are mainly round to oval shaped nanoscale pores (Fig. 4a). The organic matters pores is related to organic matter thermal evolution, during which organic matter pores develop in the organic matter and forming "honeycomb" pores (Loucks et al., 2012). Inorganic pores include residual interparticle pores, intercrystalline pore in clay minerals, carbonates recrystallization intercrystal pores and dissolution pores of unstable minerals. Interparticle pores exist among the organic matters, quartz, feldspar, calcite and pyrite framboidals grains, which are irregular shaped, with pore size in nanometer-based (Fig. 4b). Intercrystalline pore in clay minerals are rich in the clay-rich intervals (Fig. 4c). Recrystallization intercrystal pores mainly occur in the calcite, with pore size ranging from 5 to 50 μm. The generation of recrystallization intercrystal pores is related to the crystal particles becoming little in the recrystallization process. In addition, the recrystallized intercrystalline pores in dolomite are also common in the high dolomite content lithofacies, which smaller pore size and less abundance than the pores in calcite (Fig. 4d). The dissolution pores are observed in calcite and feldspar grains, which are mainly elliptical, with pore size ranging from 0.1 to 2 μm (Fig. 4e). The formation of dissolution pores is thought to be related to organic acids formed during hydrocarbon generation. Fractures include abnormal pressure fractures, tectonic fractures, interlaminar fractures and mineral contraction fractures. The abnormal pressure fractures typically extend approximately 2–10 cm (Fig. 4f), and the fracture surfaces are short and typically irregular. The abnormal pressure fractures are thought to be related to the local abnormal pressure because of organic matter thermal evolution and hydrocarbon generation (Jiu et al., 2013; Ding et al., 2012). The tectonic fractures are well developed, which is closely related to the brittle minerals content (Fig. 4g). The interlaminated fractures are abundant in the shale, which have good connectivity and act as high-quality reservoir space (Fig. 4h). In addition, the micro-fractures in the clay minerals are common in these clay-rich lithofacies.

Comprehensive analysis of pore size, relative abundance, connectivity and validity, interlaminated fractures and recrystallization intercrystal pores are high quality reservoir space types. The development of pore types and pore networks are closely related to the lithofacies, especially the inorganic pores (Deng and Liang, 2012; Liang C et al., 2012; Loucks et al., 2012). The development of organic pores are mainly depends on the type of organic matter and thermal maturity (Jarvie et al., 2007).

4.2 Porosity and Permeability

The porosity of Es_4^s–Es_3^x shale mainly ranges from 2.0% to 8.6%, with an average of 5.3%. The horizontal permeability ranges from 0.5×10^{-3} to 10×10^{-3} μm^2, while the vertical permeability is generally less than 1.0×10^{-3} μm^2, average being 0.2×10^{-3} μm^2 (Fig. 5). In general, the pores are mainly nanoscale, with a small amount of pore size up to tens of microns (Fig. 7).

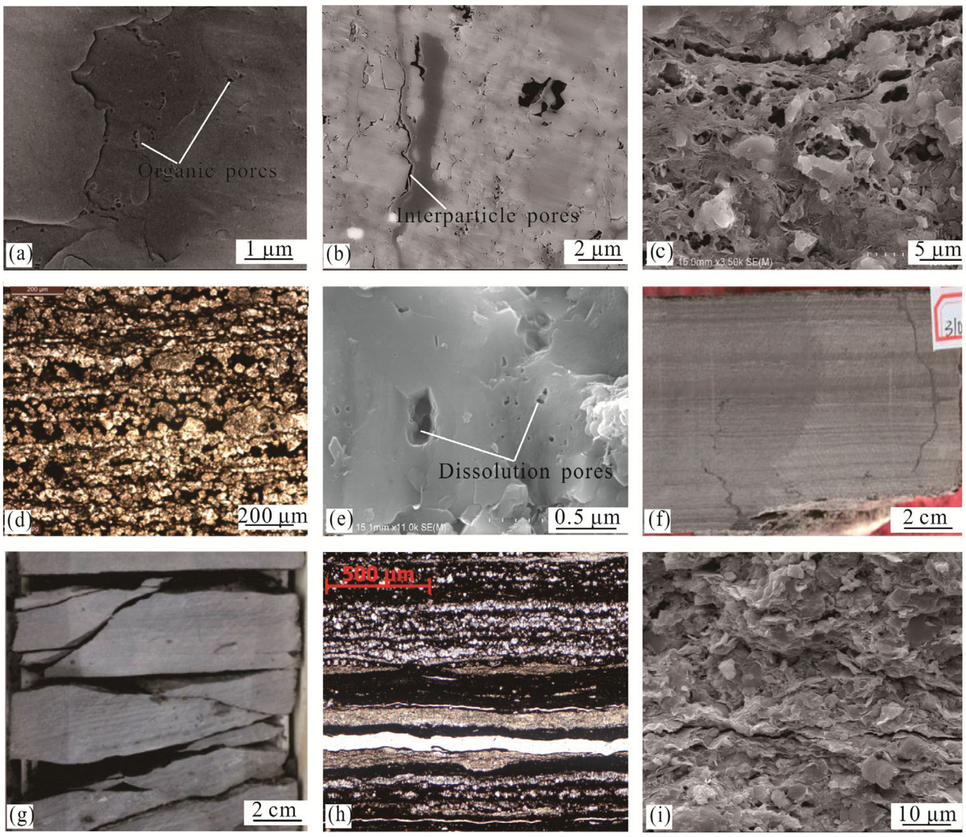

Figure 4. The characteristics of reservoir space in the shale. (a) Organic pore, Well LY1, 3 662.1 m; (b) interparticle pores, Well NY1, 3 436.23 m; (c) intracrystalline pores in clay minerals, Well FY1, 3 308.4 m; (d) calcite recrystallization intercrystal pores, Well L69, 3 042.1 m; (e) dissolution pores, Well FY1, 3 331.55 m; (f) abnormal pressure fractures, Well L69, 3 101.76 m; (g) tectonic fractures, Well NY1, 3 323.7 m; (h) interlaminated fractures, Well W31, 2 610.5 m; (i) mineral contraction fractures, Well L69, 3 056.8 m.

5 THE CONTROLS ON SHALE OIL ENRICHMENT

5.1 Hydrocarbon Generation Capacity

Hydrocarbon generation capacity is one of the most important factors for shale oil enrichment, which is mainly determined by the organic matter type, abundance of organic matter and thermal maturity. The kerogen type of Es_4^s–Es_3^x shale is mainly Type I, which has higher hydrocarbon generation potential and is the most favorable organic matter type. For maturity of organic matter, the *R*o is mainly between 0.5% and 0.75%, and the organic matter has begun the evolution of hydrocarbon generation. The Es_4^s–Es_3^x shale has high abundance of organic matter, and the TOC content ranges from 2.0% to 4.0%, which provides the necessary material basis for shale oil enrichment. At the same time, the oil production of shale is closely related to the TOC content, and it increases gradually with the increasing of TOC content, which fully proves that the TOC content plays an important role in shale oil enrichment (Fig. 6). Even though source rock has good capacity of hydrocarbon generation, it is difficult to develop a large scale hydrocarbon aggregation without stable thickness.

What's more, for the shale oil and gas, hydrocarbon is mostly in situ gathering with smaller scale or even without secondary migration (Chen et al., 2017; Liang S J et al., 2012; Lu et al., 2012; Yang and Zhang, 2012). Therefore, effective thickness of shale interval becomes another important indicator of shale oil accumulation (Song et al., 2013; Wang et al., 2013; Lu et al., 2012). Researches show that the continuous thickness of shale should be combined with other indicators of hydrocarbon generation potential. The hydrocarbon potential is greater, the requested thickness of shale is smaller (Wang et al., 2013; Chen et al., 2011). The Es_4^s–Es_3^x shale in Jiyang depression is deposited in stable deepwater environment and its horizontal distribution is relatively continuous (Fig. 8). Combined with the domestic and overseas related investigation and research, we suggest that the thickness of shale is at least 30 m, for which it can form industrial scale oil and gas accumulation. The Es_4^s–Es_3^x shale in Jiyang depression develops stably, with organic carbon content TOC>2.0% and maturity of organic matter *R*o>0.5%, shale area whose thickness greater than 50 m is up to 5 524 km^2, having good material basis for shale oil and gas (Fig. 8).

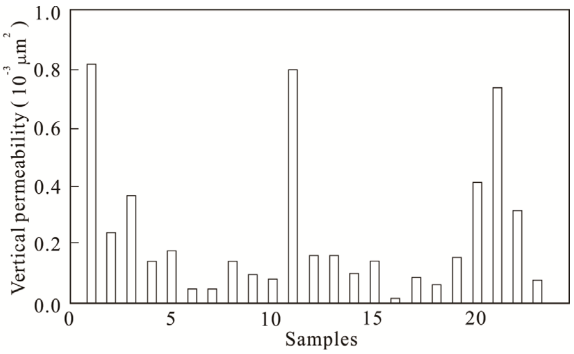

Figure 5. Vertical permeability distribution of Es_4^s–Es_3^x shale in Jiyang depression.

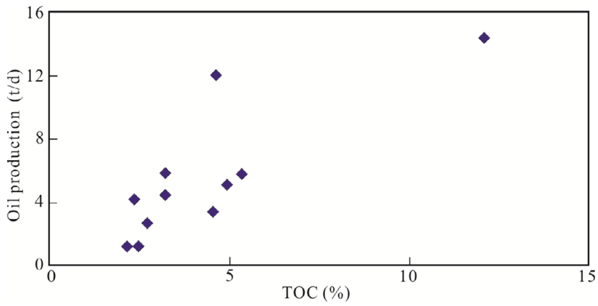

Figure 6. The relationship between TOC content and oil production.

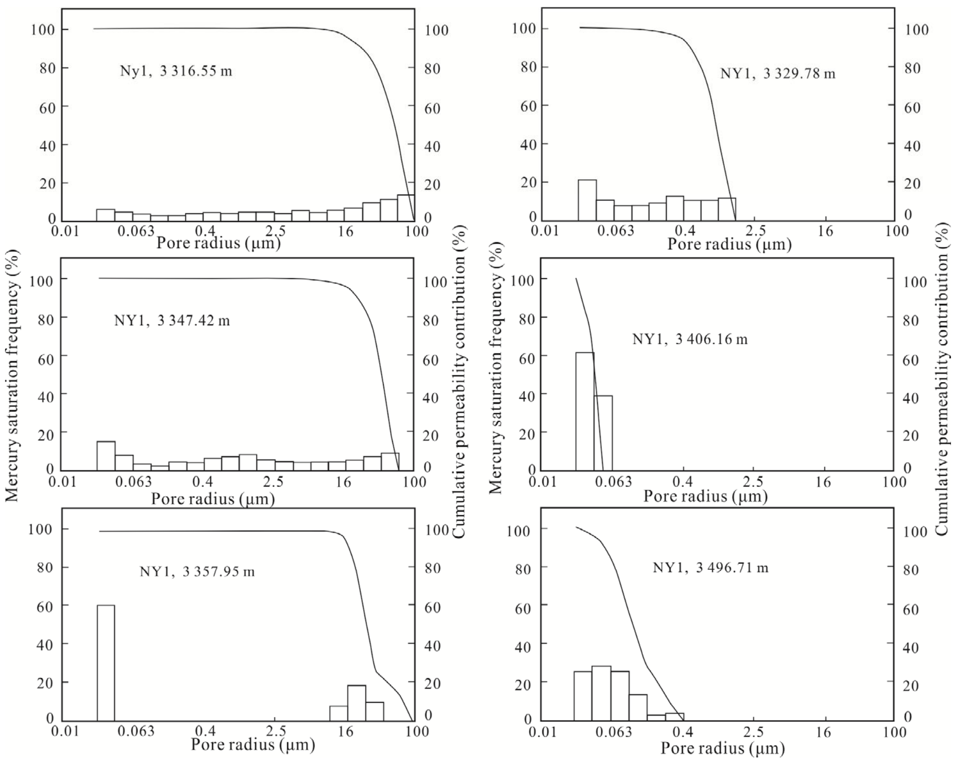

Figure 7. The pore radius distribution characteristics of Es_4^s–Es_3^x shale.

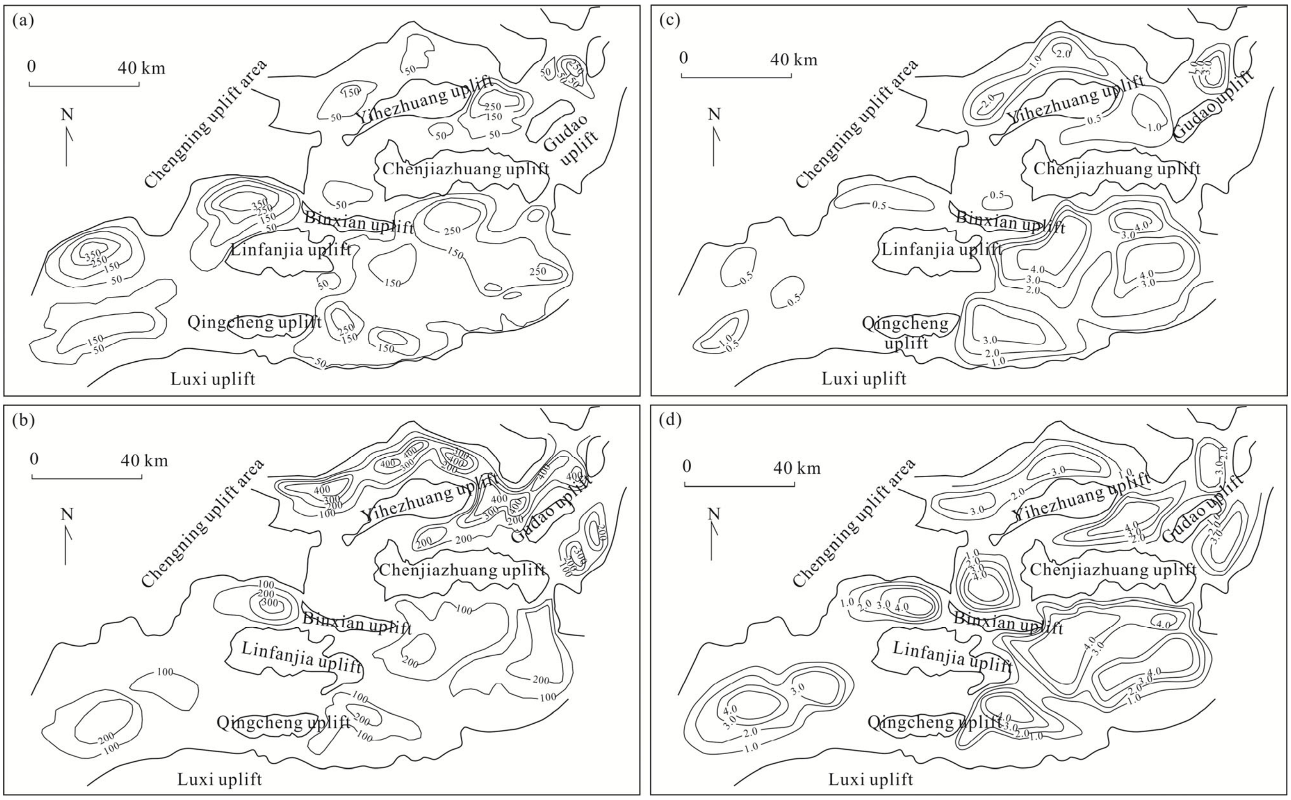

Figure 8. The contour plot of thickness and TOC content of Es_4^s shale (a), (c) and Es_3^x shale (b), (d).

Overall, the hydrocarbon generation condition of shale oil mainly depends on the source rock indicators of shale and organic rich shale thickness. For the Es_4^s–Es_3^x shale in Jiyang depression, organic matter types and thermal maturity change little. Therefore, the TOC content and stable thickness of organic rich shale become the main controlling factors of hydrocarbon generation conditions.

5.2 Reservoir Capacity

Produced in organic matters, hydrocarbon accumulated in the organic matters firstly and migrated to the inorganic pore, and then the fractures. From organic pores to inorganic pores, then to fractures, the hydrocarbon in the shale has abundant storage space and passage for migration and accumulation, which is very important for shale oil enrichment. Reservoir capability mainly depends on the reservoir pore space size, abundance and connectivity, and these characteristics are closely related to lithofacies, TOC content and tectonic fractures (Fig. 9).

The lithofacies play a crucial role on the development of reservoir space. According to the relative content of reservoir pore space development, the lithofacies mentioned above can be divided into three reservoir types: (1) the high organic laminated limestone mainly develop interlaminated fractures, tectonic fractures, intracrystalline pores in clay and organic pores, which has the best reservoir properties, with porosity greater than 8% and permeability about 1 mD; (2) the middle organic laminated marl and limy claystone develop abnormal pressure fractures, interlaminated fractures, tectonic fractures and intracrystalline pores in clay, with porosity about 5%–6% and permeability about 1 mD; (3) the low organic marl and claystone develop limited reservoir space, with porosity 2%–4%, permeability much smaller than 1 mD. In addition, the development of reservoir pore space is also related to the organic matters content, such as the organic pores generated by the OM and dissolution pores and recrystallization intercrystalline pores associated with the organic matter thermal evolution. In the high organic lithofacies, reservoir pore space content and pore size is more favorable, and the corresponding reservoir property is also better. The tectonic fractures for shale reservoir properties cannot be ignored, which can help to connect the different reservoir space and acts as an important hydrocarbon migration pathways and basis of artificial fracturing (Tang et al., 2012). The development of tectonic fractures depends on tectonic structure and the shale physical properties, such as brittleness, which is controlled by mineral composition and lithofacies. For example, a series of normal faults developed near the Well L69 (Fig. 10a), which will promote the formation of associated fractures, with fractures length up to tens of centimeters (Figs. 10b, 10c).

5.3 Shale Fracturing

The shale fracturing is a comprehensive reflection of reservoir characteristics, mainly controlled by rock brittleness. The higher brittleness means easier fracturing. Young's modulus and Poisson's ratio are important parameters to measure the rock brittleness, and higher Young's modulus and lower Poisson's ratio indicates the stronger brittleness and fracturing (Tang et al., 2012). The Young's modulus value of Barnett shale is 33.0 GPa and Poisson's ratio is about 0.2–0.3. The average values of Young's modulus and Poisson's ratio of Longmaxi shale in the Sichuan Basin are 48.9 GPa and 0.27, separately. The Young's modulus of the Es_4^s–Es_3^x shale is 20.0–45.0 MPa and Poisson's ratio is about 0.15–0.3. Therefore, contrast to the Barnett shale and the Longmaxi shale, we draw the conclusion that the Es_4^s–Es_3^x shale in Jiyang depression can be well fracturing.

The rock brittleness is related to the mineral composition and increases with an abundance of brittleness minerals (Curtis et al., 2002). As mentioned above, the brittleness mineral of the Es_4^s–Es_3^x shale is mainly carbonate minerals, with subordinate terrigenous quartz, with total brittleness minerals content up to 70%–85%. With the increasing of compaction and maturity, unstable clay minerals gradually transform into more stable clay minerals, such as illite. These processes make the shale dense, and the brittleness can be enhanced. Studies suggest that the brittleness of shale is closely impacted by the diagenesis and the shale fracability increases rapidly as the shale has high maturity (Tang et al., 2012; Jarvie et al., 2007). The diagenesis stage is broadly similar of the Es_4^s–Es_3^x shale in Jiyang depression, therefore the decisive factor for the rock brittleness is mineral composition and lithofacies.

In addition, natural fractures also play an important role on the shale fracturing, which is mainly the performance of heterogeneity of in-situ stress and developed in the relatively weak mechanical points. While its interaction with induced fractures makes fracturing effect is more obvious. Overall, the fracturing of shale reservoirs is mainly controlled by the lithofacies and tectonic activity.

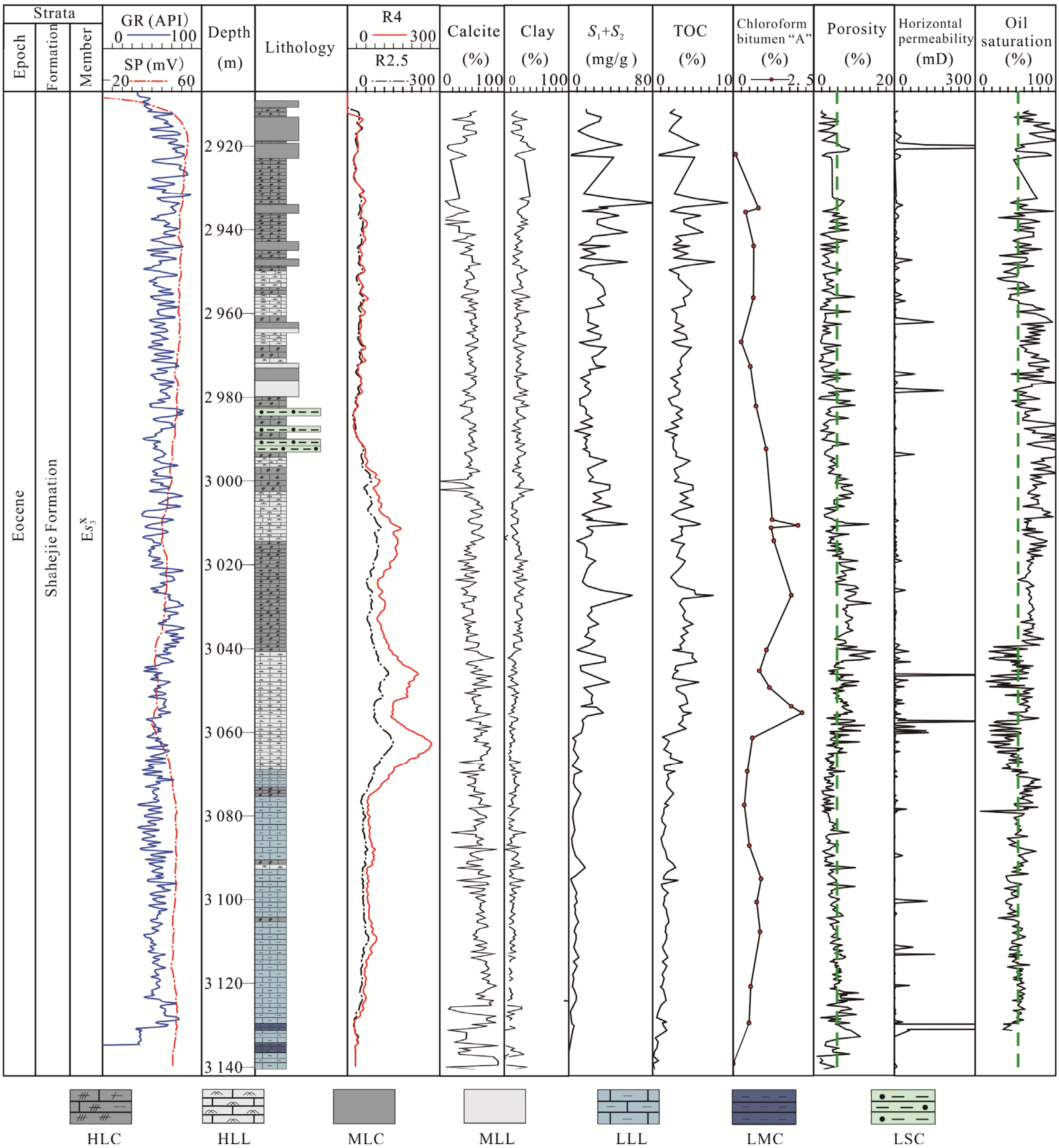

Figure 9. The lithofacies-organic geochemistry-physical properties comprehensive column of Es_3^x shale in Well L69.

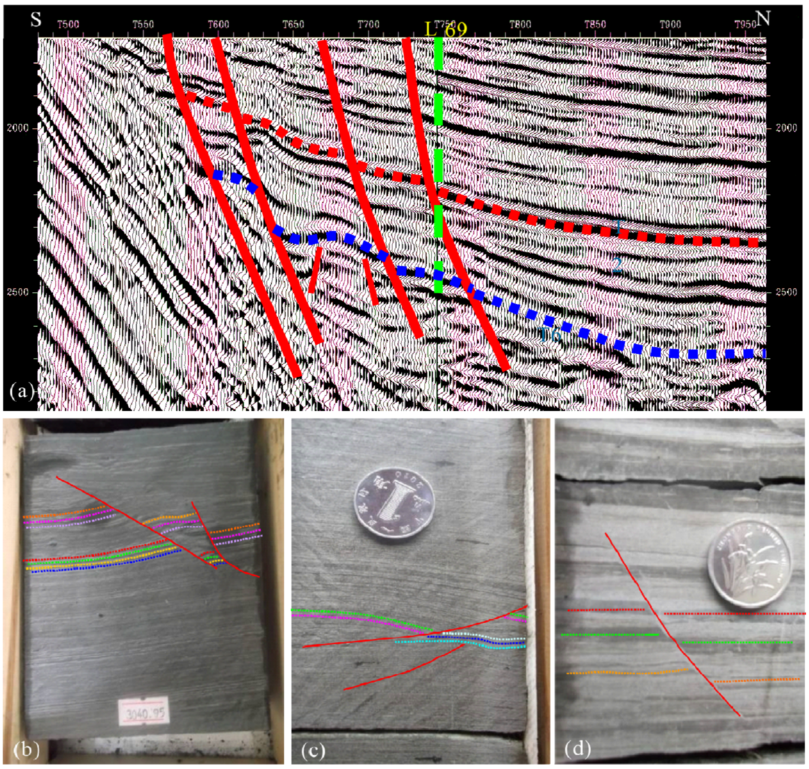

Figure 10. The seismic profile characteristics and the development of the core fractures in the Well L69. (a) The seismic profile characteristics, line No. L842; (b)–(d) the fractures in the cores of Well L69.

6 CONCLUSIONS

The Es_4^s–Es_3^x shale predominately consists of calcite and clay minerals. According to the TOC content (2% and 4%), carbonate and clay minerals, nine lithofacies have been identified in the Es_4^s–Es_3^x shale. The reservoir pore space are abundant, including organic pores, inorganic pores and fractures. Inorganic pores include residual interparticle pores, intracrystalline pores in clay minerals, recrystallization intercrystal pores and dissolution pores. The fractures include abnormal pressure fractures, tectonic fractures, interlaminated fractures and micro fractures. The development of reservoir space is mainly controlled by the mineral composition, lithofacies, TOC content and diagenesis. The shale oil enrichment is manly controlled by the hydrocarbon generation capacity and reservoir capacity. The former depends on the TOC content and thickness of organic-rich shales, and the latter is mainly related to lithofacies, TOC content and tectonic fractures. In addition, the shale fracturing will also affect the shale reservoir and shale oil production, which is controlled by the lithofacies, tectonic activity and formation pressure. Overall, shale oil reservoir evaluation should focus on the TOC content, organic-rich shale thickness, lithofacies, tectonic factors, and so on.

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