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Classification and potential of continental shale oil resources in China and resource evaluation methods and criteria

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Abstract. *Continental shale oil resource is an important alternative source for increasing and stabilizing China's crude oil production. China has abundant continental shale oil resources. The opinions of researchers are divided over the classification of shale oil resources in China, resource evaluation methods and criteria, and resource potential prediction. Considering this fact, the authors of this article first summarized and analyzed the exploration progresses made in the typical shale oil exploration areas in China and the geological insights gained through exploration activities. Then, based on the current shale oil research status and actual oil production conditions in China, shale oil resources were classified into three types: interlayer shale oil, pure shale oil, and in-situ converted shale oil. Furthermore, the corresponding resource evaluation methods and quantitative models were proposed, the key parameters and their lower limits were determined and the resources of the three major types of shale oil in the shale formations in China's major basins were evaluated using a set of unified evaluation criteria. The in-place resources of pure shale oil, interlayer shale oil and in-situ converted shale oil are* 145.4×10^8 *t,* 95.1×10^8 *t and* 708.2×10^8 *t, respectively, and the recoverable resources are respectively* 9.4×10^8 *t,* 7.1×10^8 *t and* 460.3×10^8 *t. The research results can provide guidance for the evaluation of shale oil resources in China and the exploration planning for such resources and serve as valuable references for international peers to understand China's current status of research and development potential of shale oil.*

Keywords: *shale oil, exploration progress, resource potential, resource evaluation, evaluation methods and criteria, interlayer shale oil, pure shale oil, in-situ converted shale oil.*

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1. Introduction

Relying on its breakthroughs in horizontal good and reservoir volume stimulation technologies and their extensive application, the United States (U.S.) achieved leapfrog progress in the exploration and development of marine shale oil in the early 21st century. During this period, seven shale oil-producing areas, including the Wolfcamp Formation in the Permian Basin, the Bakken Formation in the Williston Basin, and the Eagle Ford Formation in the Western Gulf Basin, were successively developed. In 2019, the crude oil output of the United States reached 609 million tons, overtaking those of Saudi Arabia and Russia, and the U.S. became the world's largest crude oil producer. In particular, the U.S.' shale oil output reached 3.96×10^8 t, accounting for 65% of its total oil production [1, 2], which helped it achieve energy independence and significantly changed the global pattern of energy supply and the geopolitical landscape. Inspired and encouraged by the success of the U.S. shale revolution, two major Chinese oil companies, namely, China National Petroleum Corporation (CNPC) and China Petroleum & Chemical Corporation (Sinopec), together with the China Geological Survey (CGS), began to study and explore shale oil exploration and development in 2008. By 2021, China had made important breakthroughs in the exploration and trial production of continental shale oil, and the annual shale oil output had reached nearly three million tons. Important discoveries were made successively in some organic-rich continental shale formations. These included the Permian Lucaogou Formation in the Jimusar Sag of the Junggar Basin [3–6], the 7_3 Sub-member of the Triassic Yanchang Formation in the Ordos Basin [7, 8], the Second Member of the Paleogene Kongdian Formation in the Cangdong Sag at the center of the Bohai Bay Basin [9, 10], the Third and Fourth Members of the Paleogene Shahejie Formation in the Boxing Sag, the Niuzhuang Sag, and the Bonan Sag of the Jiyang Depression [11–13], the First and Second Members of the Cretaceous Qingshankou Formation in the Songliao Basin [14–18], and the Jurassic shales in the northeastern Sichuan Basin [19, 20]. These shale formations show bright prospects for the development of continental shale oil. China has started the construction of three national-level continental shale oil demonstration areas, namely, the Jimsar Sag in Xinjiang Oilfield, the Gulong Sag in Daqing Oilfield, and the Jiyang Depression in Shengli Oilfield. According to the preliminary estimates made by different scholars and institutions, the in-place resources of continental shale oil in China amount to $100–3{,}722 \times 10^8$ t, including $30–372 \times 10^8$ t of recoverable resources [21–27]. Due to its tremendous resource potential, continental shale oil is considered a potential alternative to oil resources in China.

To provide theoretical guidance and a summary of rules for exploration practices, many scholars have conducted extensive research on continental shale oil with a focus on its definition, classification, criteria for evaluating shale oil accumulation zones/intervals, reservoir characteristics, and accumulation mechanism and gained preliminary results and understandings. Depending on origin, physical properties, burial depth, and recovery conditions, Zhang et al. [28] classified shale oil resources into two types, namely, oil(-bearing) shale and shale oil coexisting or associated with shale gas. Ning [29] classified shale oil resources into mud shale type and interlayer type based on occurrence space and reservoir rock type. In addition, he further classified the mud shale-type shale oil resources into matrix type and fracture type and then classified the interlayer-type shale oil resources into sandstone interlayer type and carbonate interlayer type. Fu et al. [30] classified the shale oil resources in the Chang 7 Member in the Ordos Basin into interlayer type and shale type according to sedimentary facies zone and lithological association. Moreover, the researchers further divided the interlayer-type shale oil resources into gravity flow type and delta front type and the shale-type shale oil resources into laminated type and lamellated type. Song et al. [12] classified the shale oil resources in the Jiyang Depression into matrix type, fracture type, and mixed type based on lithological association and reservoir space type. Du et al. [21] classified the continental shale oil resources in China into medium- to high-maturity shale oil and medium- to low-maturity shale oil depending on the thermal maturity of shale formations. Based on different lithological associations of shale formations, they further classified medium- to high-maturity shale oil resources into three subtypes: source-reservoir synchronogenic type, source-reservoir separated type, and exclusive shale type. Zhao et al. [23] suggested that medium- to high-maturity shale oil resources be classified into pure shale oil, tight shale oil, and transitional shale oil, with a view to both maximizing the consistency of the named standards and highlighting the differences in accumulation characteristics and development methods.

With regard to research on the methods for evaluating shale oil resources, volumetric methods are the primary means to assess interlayer shale oil where shales are not reservoirs. Such methods are not detailed herein due to their similarity to the volumetric methods used for tight oil evaluation. Volumetric methods are chiefly used to evaluate pure shale oil resources where shales are reservoirs. Modica et al. [31] proposed the organic pore model and used it to evaluate the Mowry shale oil in the Powder River Basin in the United States. Chen et al. [32] presented an improved method for calculating organic pores and evaluated the shale oil of the Duvernay Formation in the Western Canada Basin. Yang et al. [33] studied the distribution of porosity in shale formations and evaluated the shale oil in the Yanchang Formation in Ansai region of the Ordos Basin using a volumetric method. Xue et al. [34] corrected the content of thermally decomposable hydrocarbons (S1) in the Qingshankou Formation in the Songliao Basin and evaluated the shale oil therein by correcting the content of chloroform asphalt “A” in the shales of this formation. Yu et al. [35] evaluated the shale oil in the Shahejie Formation of the Dongying Sag using the content of S1 in shales and predicted the distribution of favourable shale oil zones. Zhu et al. [36] assessed the in-place and recoverable resources of shale oil in the Third Member of the Shahejie Formation in the Dongying Sag using the contents of chloroform asphalt “A” and S1. To date, no quantitative models have been developed for the evaluation of medium- to low-maturity shale oil (in-situ converted shale oil) resources.

In summary, extensive research has been conducted on the classification and evaluation of shale oil resources, but given the fact that the exploration and development of continental shale oil in China are still at the initial stage, the current understandings in some fields related to shale oil remain relatively rudimentary. In addition, there are two key outstanding issues, which are described below.

One is concerned with the classification of shale oil resources and the resource potential of various types of shale oil. Regarding the classification of shale oil resources, the national standard has been established, but no description of "whether in-situ converted shale oil should be included" has been provided. Additionally, due to the differences in the research subjects, research focuses, and classification criteria adopted by different scholars, as well as for many other reasons, a number of separate schemes have been proposed, and there has been a significant divergence of opinion among scholars. As to the resource potential of shale oil, scholars and research institutions have proposed varying ranges of resource potential. However, it is difficult to perform horizontal comparisons of shale oil resources because there are many different types of such resources. Moreover, the great differences in the quantity of resource given in different studies make it difficult to accurately determine and realize the potential of shale oil resources in China.

The other issue is related to the methods and key criteria for evaluating various types of shale oil. There are many different methods for evaluating shale oil resources, such as the volumetric method and the analogy method. However, the details of quantitative evaluation and the differences between various exploration stages have not been clearly presented. Additionally, there is no quantitative evaluation method available for in-situ converted shale oil. Regarding studies on the key parameters for evaluating shale oil resources, no consensus has been reached on the lower limits of such parameters, and no relevant standards have been established at the national, industrial, and enterprise levels. These factors restrict the smooth performance of evaluations of shale oil resources.

In this study, the exploration progresses and understanding of typical shale oil exploration areas in China are investigated and summarized. Then, based on the actual conditions of current research on shale oil and shale oil production in China, shale oil resources are classified into three types: interlayer shale oil, pure shale oil, and in-situ converted shale oil. Furthermore, the quantitative models for evaluating the corresponding types of shale oil resources are proposed based on the differences between evaluation datasets that can be obtained at different exploration stages. Finally, unified evaluation criteria are adopted to screen evaluation areas and estimate the potential of the three types of shale oil resources in China. The research results are expected to provide valuable guidance for the evaluation of shale oil resources in the country and the planning of related exploration activities.

2. Exploration progresses and understandings of typical shale oil exploration areas in China

2.1. Shale oil in the Triassic Chang 7_3 Sub-member in the Ordos Basin

2.1.1. Exploration and discovery history

The Chang 7 Member of the Triassic Yanchang Formation in the Ordos Basin is a mud shale-dominated source rock system formed at the peak stage of the Late Triassic continental freshwater basin. The thickness of this member is approximately 110 m. From bottom to top, it is subdivided into the Chang 7_3 Sub-member, the Chang 7_2 Sub-member, and the Chang 7_1 Sub-member. The Chang 7_3 Sub-member mainly consists of black shales that are extremely rich in organic matter and are interbedded with thin siltstone and fine-grained sandstone layers. The Chang 7_2 Sub-member and the Chang 7_1 Sub-member are mainly composed of gray mudstone with a relatively low content of organic carbon interbedded with argillaceous siltstone, siltstone, and fine-grained sandstone layers. In general, the thickness and grain size of the sand body tend to increase from bottom to top with the shrinking of the lake basin and the shallowing of the water body.

Through exploration for more than 10 years, PetroChina Changqing Oilfield Company has carried out volume fracturing and stimulation tests successively in 30 vertical wells drilled through the thick-bedded mud shale interval of the Chang 7_3 Sub-member. Industrial oil flows have been obtained in 14 wells, marking a major breakthrough in the production of shale oil from the aforesaid interval. However, the results of trial production show that it is very difficult to maintain stable production from this interval. In 2019, Changqing Oilfield Company deployed two horizontal wells, namely, Well Chengye-1 and Well Chengye-2, in the Cheng 80 Block to conduct risk exploration activities and tests targeted at the shale oil in the thick mud shale layer interbedded with thin siltstone and fine-grained sandstone layers in the Chang 7_3 Sub-member of the Yanchang Formation in the Ordos Basin. The oil flows obtained from Well Changye-1 and Well Changye-2 through well tests were 121.38 t/d and 108.38 t/d, respectively. In 2021, Well LY1H, which is a risk exploration well, was deployed at the periphery of the Maling-Huachi deep depression zone to further explore the exploration potential of the shale oil in the more fine-grained and thinner sandy rocks in the Chang 7_3 Sub-member. By developing fracturing techniques and optimizing the drainage mechanism, a major exploration breakthrough was made in Well LY1H, and a high oil flow rate of 116.8 t/d was obtained by well testing. This achievement has opened up new prospects for shale oil exploration in the Chang 7_3 Sub-member.

Figure 1 displays the spatial distribution of shale thickness and isoline of Ro in the Triassic Chang 73 Sub-member of the Ordos Basin.

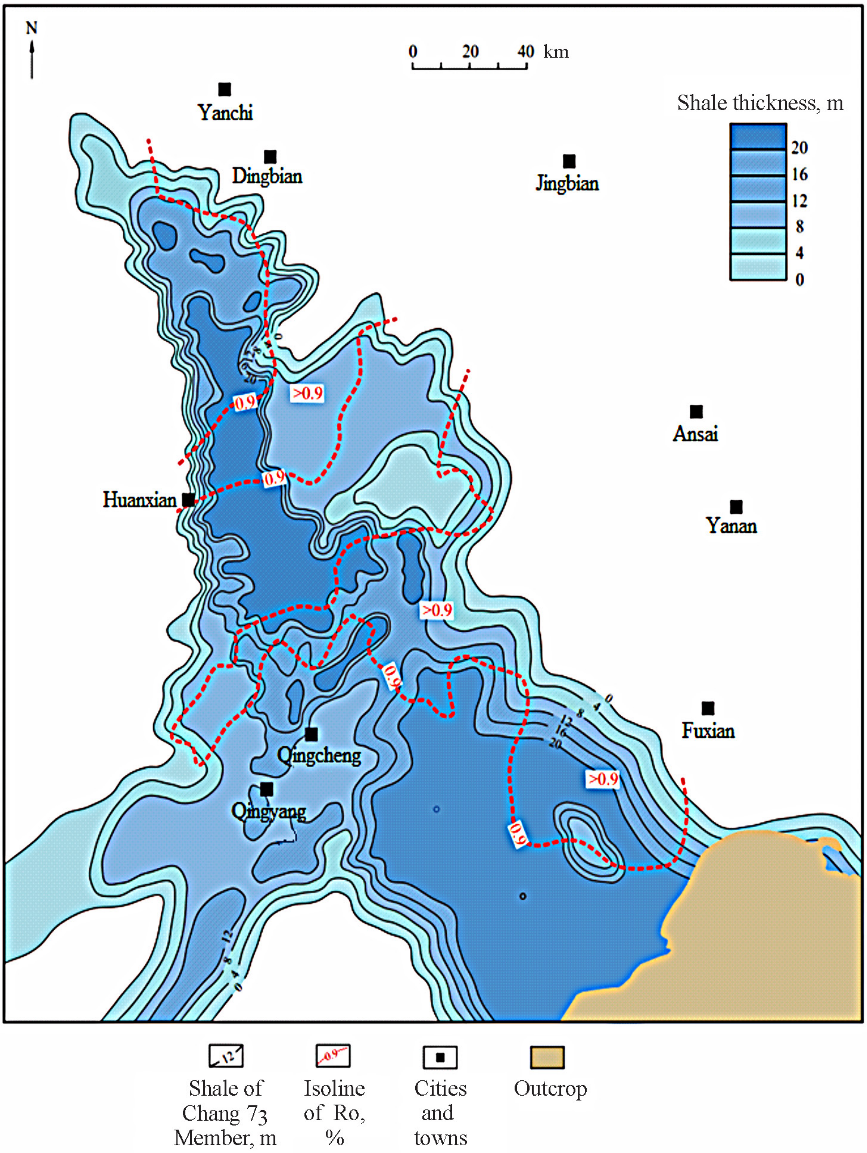

Fig. 1. Spatial distribution of shale thickness and isoline of Ro in the Triassic Chang 7_3 Sub-member of the Ordos Basin.

2.1.2. Characteristics of shale oil

2.1.2.1. Characteristics of source rocks

Two types of high-quality source rocks, namely, black shale and dark mudstone, have been proved. The average total organic carbon (TOC) of black shale is 13.81%, and that of dark mudstone is 3.74%. The main types of organic matter in the black shale are Type I and Type II_1 and those in the dark mudstone are Type II_1 and Type II_2. The oil-generating kerogens in both types of source rocks have reached maturity. For these kerogens, Ro ranges from 0.7% to 1.2%, the peak temperature of thermal decomposition (expressed by Tmax) is higher than 450 °C, indicating that the kerogens are at the peak of oil generation, and the average content of S1 is 4.57 mg/g.

2.1.2.2. Characteristics of reservoir spaces

The accumulated oil and gas are stored in the thin layers of siltstone and fine-grained sandstone interbedded between thick shales. The source and reservoir rocks are separated from each other. The average thickness of fine-grained sandstone and siltstone layers in the Cheng 80 Block is 3.5 m, and the average single-layer thickness in the LY1H well area is only 0.97 m. The average porosity and average permeability of reservoirs are 6.7% and 0.045×10^{-3} μm^2, respectively. The reservoir spaces are mainly composed of intergranular pores, dissolution pores, intercrystalline pores, and fractures.

2.1.2.3. Characteristics of reservoirs

The density of crude oil is within the range of 0.80–0.86 g/cm^3, its average viscosity is 1.55 mPa·s. The gas-oil ratio (GOR) is within the range of 60–120 m^3/t. The pressure coefficient ranges between 0.7 and 0.9, which obviously indicates negative pressures in reservoirs. The oil saturation ranges from 70% to 90%, which is higher than the oil saturation levels of the good thick reservoirs in the upper Chang 7_{1+2} Sub-members. In general, the oil is light, highly mobile, and buried at small depths (ranging between 700 m and 2,900 m). Therefore, the geological conditions are favourable for large-scale commercial development.

2.1.2.4. Development degree of fractures

Fractures have developed well, especially in fine-grained sandstones. Most fractures are tectonic fractures, and more than 70% of them have not been filled.

2.1.2.5. Content of clay minerals

The content of clay minerals is within the range of 28.7–34.0%. The content of quartz ranges between 13.6% and 29.3%, and that of feldspar is between 2.7% and 8.8%. The content of the illite/smectite mixed-layer minerals is the highest, ranging from 79% to 85%. The content of illite ranges from 7% to 10%, and that of kaolinite is between 2% and 5%.

2.1.3. Main factors controlling the accumulation of shale oil

Fu et al. [37] summarized four main factors controlling the accumulation of shale oil in the Chang 7 Member. These controlling factors are described below. First, the widely distributed black shales and dark mudstones serve as the material basis and abundant source of shale oil. Second, the thin layers of sandy rock sandwiched between the thick layers of organic-rich shale constitute the “sweet spots” rich in oil. Third, many micro-scale pores and nano-scale pore throats of varying sizes are distributed in fine-grained sandstone and siltstone reservoirs, and high mobility of fluids in these pores and throats can be achieved by means of fracturing. Fourth, intense hydrocarbon generation has continued for multiple geological periods, resulting in a pressure difference of 8–16 MPa between source rocks and thin reservoirs, and large shale oil accumulation zones with oil saturation levels higher than 70% have been formed by intense dynamic filling.

2.2. Shale oil in the Qingshankou Formation of the Gulong Sag in the northern Songliao Basin

2.2.1. Exploration history

Significant breakthroughs have been made in shale oil exploration in the First and Second Members of the Cretaceous Qingshankou Formation of the Gulong Sag in the northern Songliao Basin in the last two years. The high yield from Well Guye Youping #1 obtained through well testing in early 2020 marks a great success in the exploration of pure shale formation. Up to date, this well has been producing oil and gas by natural flow for more than 480 days, with a daily oil production of 13 t and a daily gas production of 8,310 m^3 during the period of stable production. Based on geological insights, available technologies and other factors, Wang et al. [15] divided the history of shale oil exploration in the Gulong Sag in the northern Songliao Basin into three stages: the discovery and exploration stage (from 1981 to 2009), the research stage (from 2010 to 2017), and the testing and breakthrough stage (from 2018 to the present time). In the discovery and exploration stage, an industrial oil flow was first obtained from Well D12, which was deployed and drilled in 1981 (with a daily oil production of 3.83 t/d and a daily gas production of 441 m^3/d), by well testing in the First and Second Members of the Qingshankou Formation. The discovery of the fractured mudstone reservoir in the Qingshankou Formation confirmed the existence of mud shale oil resources. In the research stage, inspired by the success in the exploration and development of shale oil and shale gas in the U.S., Exploration Well E was drilled and completed in the reservoir composed of shales interbedded with thin sandstone layers in the Second Member of the Qingshankou Formation using the tight oil exploration concept and technology. Twelve intervals of this well were modified by large-scale fracturing, and a daily industrial oil flow of 10.2 t was obtained thereby. Later, two horizontal wells were deployed and drilled in the E well area. A daily industrial oil flow of 14.3 t/d was obtained from Well E-1, which proved the conditions for high production of shale oil and boosted the confidence of Daqing Oilfield Company in shale oil exploration. During the testing and breakthrough stage, in order to further expand the achievements of shale oil exploration in the Qingshankou Formation in the northern Songliao Basin and explore the pure shale reservoirs in the semi-deep to deep lake area, Daqing Oilfield Company drilled wells CP-1 and CP-2 in the Qijianan-Gulong Sag in cooperation with the China Geological Survey. The daily industrial oil flows from these wells were 11.9 t and 9.8 t, respectively, showing the bright prospect of pure shale reservoirs. To enable exploration breakthroughs in this area and investigate the oil-bearing properties and production capacities of highly mature pure shale reservoirs, Daqing Oilfield Company deployed and drilled Well A in the deep interval of the Gulong Sag in 2018. Later, Horizontal Well A-1 was drilled and completed in 2019, and high-yield industrial oil and gas flows were obtained from this well. The well's daily oil production and daily gas production by natural flow were 22.6 m^3 and 10,823 m^3, respectively.

Figure 2 shows the division diagram of the favourable area for shale oil in the First and Second Members of the Qinshankou Formation in the northern Songliao Basin.

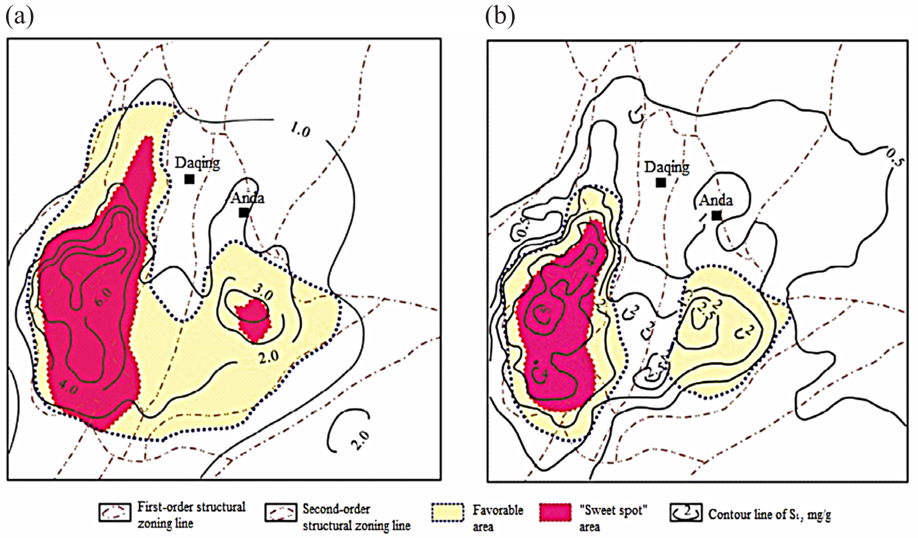

Fig. 2. Division diagram of the favourable area for shale oil in the First and Second Members of the Qinshankou Formation in the northern Songliao Basin: a) the First Member of the Qinshankou Formation; b) the Second Member of the Qinshankou Formation (modified from [15]).

2.2.2. Characteristics of shale oil

2.2.2.1. Characteristics of source rocks

In the deposition period, semi-deep to deep freshwater lake facies were widely developed in the First and Second Members of the Qingshankou Formation in the Gulong Sag, and ultra-thick mudstones (shales) with a thickness of 320 m were deposited. The TOC content in the First Member of the Qingshankou Formation is generally higher than 2.0% and can reach 10% as confirmed by the results of well drilling. The TOC content in the Second Member of the Qingshankou Formation is relatively low, usually ranging from 1.0% to 2.0%, and the average TOC content in this member is 1.5%. In general, the main types of organic matter in the First and Second Members of the Qingshankou Formation are Type I and Type II_1, and the main hydrocarbon-generating kerogens are lamellar algae. The Ro of the First Member of the Qingshankou Formation ranges between 0.75% and 1.7%, and that of the Second Member of the Qingshankou Formation is in the range from 0.75% to 1.5%. The content of S1 is usually higher than 4 mg/g.

In Figure 3, the stratigraphic characteristics of the Qingshankou Formation in the northern Songliao Basin are presented.

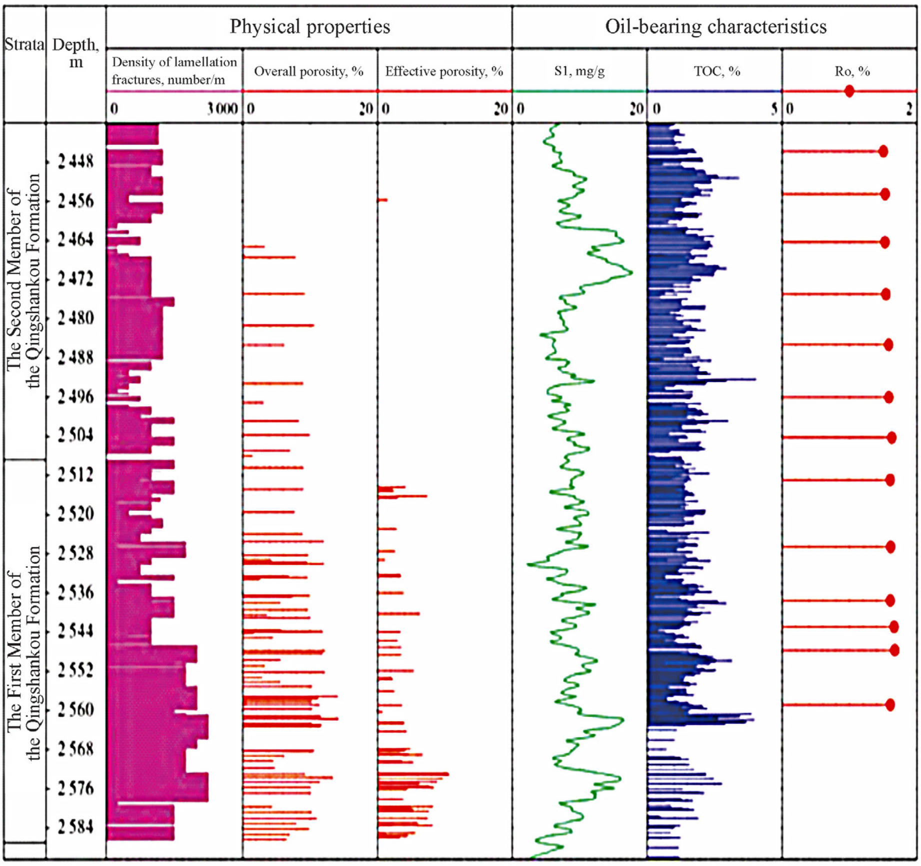

Fig. 3. Stratigraphic characteristics of the Qingshankou Formation in the northern Songliao Basin (modified from [18]).

2.2.2.2. Characteristics of reservoir spaces

Five lithofacies were identified in the shale formation in the Gulong Sag. These facies are shale, mudstone, siltstone, calcareous rock, and dolomitic rock. The cumulative thickness of layered and laminated shales accounts for more than 90% of the total thickness of the First and Second Members of the Qingshankou Formation. Furthermore, these five lithofacies are characterized by high effective porosity and high horizontal permeability and are the dominant reservoir rocks for shale oil in the Gulong Sag. The network of matrix pores in the shale formation is mainly composed of nano- to micro-sized pores and also includes densely distributed lamellated and tectonic fractures, which form a complex pore-fracture system. The source and reservoir rocks are synchronogenic, providing necessary spaces for the accumulation of pure shale oil. The core analysis data shows that the shale formation in the Gulong Sag contains six types of pores and fractures falling within the following two major categories: inorganic pores and fractures (including intergranular pores, intragranular pores, intercrystalline pores, and inorganic lamellated fractures) and organic pores and fractures (including intra-organic pores and organic lamellated fractures). These pores and fractures are characterized by the development of spongy organic pores and organic lamellated fractures formed by the shrinkage of lamellar algae during hydrocarbon generation. The total porosity of shales is high, usually ranging between 5% and 14%, and the effective porosity is usually in the range of 2–6%. The matrix permeability is extremely low. However, due to lamellation, the horizontal permeability at the overburden pressure (27 MPa) is high, ranging between $0.011 \times 10^{-3}\ \mu m^2$ and $1.62 \times 10^{-3}\ \mu m^2$.

2.2.2.3. Characteristics of reservoirs

The density and average viscosity of crude oil are $0.784\ g/cm^3$ and 2.7 mPa·s, respectively. The GOR is high and can reach $2{,}000\ m^3/m^3$. The pressure coefficient ranges from 1.2 to 1.5, which is an obvious indication of overpressure. The oil saturation ranges between 40% and 65%.

2.2.2.4. Development degree of fractures

Tectonic and lamellated fractures, especially lamellated fractures in the horizontal direction, are well developed, resulting in high horizontal permeability.

2.2.2.5. Content of clay minerals

The content of clay minerals is high, usually ranging between 30% and 40%, and the content of brittle minerals is low. However, smectite and kaolinite have been mostly transformed into illite due to the high degree of diagenetic evolution. Consequently, some siliceous minerals have been segregated, the degree of crystallization of minerals has increased, and the directional alignment of minerals has been improved. Therefore, the fracturability of shales has become better, making up for the deficiency caused by the high content of clay minerals.

2.2.3. Main factors controlling the accumulation of shale oil

He et al. [16] summarized four main factors controlling the accumulation of shale oil in the Gulong Sag. These controlling factors are described below. First, the thick shale layers with high organic matter content that have developed on a large scale provide the material basis for the accumulation of shale oil. Second, the high degree of thermal evolution is a key factor controlling the accumulation of shale oil. Third, a large number of lamellated fractures and matrix pores have developed in pure shales, which is an important factor in ensuring the accumulation of shale oil. Fourth, the existence of abnormally high pressures is a necessary condition for the accumulation and high yield of shale oil.

2.3. Shale oil in the Lucaogou Formation of the Jimsar Sag in the Junggar Basin

2.3.1. Exploration and discovery history

Wang et al. [5] systematically summarized the history of shale oil exploration and discovery in the Jimsar Sag of the Junggar Basin and divided it into three stages: the exploration and discovery stage (from 2010 to 2011), the development and pilot test stage (from 2012 to 2015), and the key breakthrough stage (from 2016 to the present time). In the exploration and discovery stage, in September 2011, Well Ji-25 was tested at the 3,403–3,425 m interval in the Lucaogou Formation, from which the daily oil production of 18.25 t was achieved by swabbing, and the cumulative oil production reached 264.94 t. In this way, shale oil was discovered in this formation. In the exploitation and pilot test stage, tests of separate-layer fracturing and multi-layer commingled production were performed in vertical wells, and tests of large-scale hydraulic fracture stimulation (fracturing) were carried out in horizontal wells to increase production. In this stage, 22 exploration and appraisal wells were drilled, 23 intervals of 18 wells were tested, and industrial oil flows were obtained from 20 intervals in 15 wells, which verified the existence of the upper and lower “sweet spots.” The maximum daily oil production from Well Ji-172_H (a horizontal well) was 77.8 t in the initial production stage. During the key breakthrough stage, based on a summary of experiences from the previous pilot tests, it was proposed to improve the probability of penetration into oil reservoirs during drilling from a geological perspective and determine the technical countermeasures for good segmentation and hydraulic fracturing with large quantities of sand at high flow rates from an engineering perspective. In 2016, two horizontal wells were deployed in the Ji 37 well area. The maximum daily oil production from Well JHW025 was

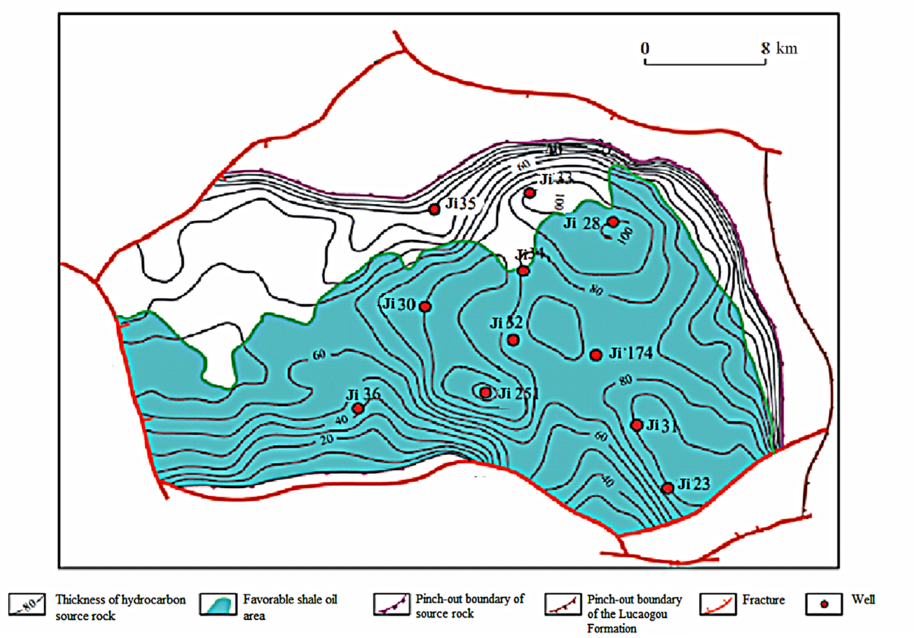

Fig. 4. Favourable areas of source rock and shale oil in the Jimsar Sag of the Junggar Basin.

108.5 t, and that from Well JHW023 was 79.9 t, showing good prospects for the development of shale oil in the Lucaogou Formation of the Jimsar Sag.

Favourable areas of source rock and shale oil in the Jimsar Sag of the Junggar Basin are shown in Figure 4.

2.3.2. Characteristics of shale oil

2.3.2.1. Characteristics of source rocks

The Middle Permian Lucaogou Formation in the Jimsar Sag took shape in the sedimentary environment of a saline lake after the closure of the residual marine basin. A sequence of shallow-deep lacustrine organic-rich diamictites composed of fine-grained mud shales, siltstones, and carbonate rocks was formed under the combined action of mechanical deposition, chemical deposition and biological deposition. The Lucaogou Formation, which is the most important source rock formation in the Jimsar Sag, is composed primarily of grayish-black mudstone and dolomitic mudstone. This formation is vertically divided into two members, namely, the upper and lower members. Each member is subdivided into three sub-members, among which the second sub-member is a shale oil "sweet spot" with high oil content. The TOC content of the Lucaogou Formation is generally higher than 2.0%, usually ranging from 2.0% to 14.0%. In this formation, the main types of organic matter are Type I and Type II_1; the Ro value ranges between 0.52% and 1.03%; and the content of S1 is within the range of 0.01–3 mg/g.

2.3.2.2. Characteristics of reservoir spaces

The reservoir in the lower "sweet spot" interval (the First Member of the Lucaogou Formation) mainly consists of thin layers of dolomitic siltstone, dolomicrite, and argillaceous siltstone, and the single-layer thickness ranges from 0.2 m to 2.0 m. The reservoir in the upper "sweet spot" interval (the Second Member of the Lucaogou Formation) is mostly composed of thin layers of dolarenite and dolomitic siltstone, and the single-layer thickness ranges between 1.0 m and 2.0 m. As indicated by microscopic observations, the reservoir space in the Lucaogou Formation is primarily composed of carbonate intergranular and dissolution pores, terrigenous clastic intergranular pores, and intergranular dissolution pores. The experimental results with respect to petrophysical properties show that the reservoirs in the Lucaogou Formation are characterized by relatively high porosity and relatively low permeability. For these reservoirs, the porosity at the overburden pressure ranges from 5.52% to 19.84%, and the median porosity is 9.59%; the permeability at the overburden pressure is within the range of 0.0004×10^{-3} μm^2 to 1.950×10^{-3} μm^2, and the median permeability is 0.013×10^{-3} μm^2.

2.3.2.3. Characteristics of reservoirs

The density of crude oil at the surface ranges between 0.89 g/cm^3 and 0.91 g/cm^3 and is 0.9 g/cm^3 on average. The average viscosity of crude oil at 50 °C is 53.03 mPa·s in the upper "sweet spot" interval and 166 mPa·s in the lower "sweet spot" interval. The GOR is relatively low, ranging between 13 m^3/m^3 and 24 m^3/m^3. The pressure coefficient is within the range of 1.1–1.3. The oil saturation is high, ranging from 70% to 95%.

2.3.2.4. Development degree of fractures

Lamellated fractures are the main type of fractures. Visible sutures have been observed. Microfractures are underdeveloped.

2.3.2.5. Content of clay minerals

The content of clay minerals is low, usually lower than 15%. The content of brittle minerals is higher than 80%.

2.3.3. Main factors controlling the accumulation of shale oil

The main factors controlling the accumulation of shale oil in the Jimsar Sag are described below. Organic-rich source rocks are widely distributed in the saline lake basin, which ensures the retention of abundant shale oil. The relatively high porosity of multiple types of reservoirs composed of mixed sediments ensures high oil saturation. The top and bottom seals ensure the high mobility of liquid hydrocarbons.

3. Classification of shale oil resources in China

Shale is a fine-grained sedimentary rock formed by dehydration and cementation of clay. It is mainly composed of clay minerals and has obvious laminated structure. Oil shale is a high-ash solid combustible rock. It is organic-rich shale with an oil content higher than 3.5%. Shale oil (general definitions in [38, 39]) can be obtained from oil shale through destructive distillation or underground in-situ cracking. As defined by Dyni [40], oil shale is a fine-grained sedimentary rock containing organic matter that will yield substantial amounts of oil and combustible gas upon destructive distillation. A deposit of oil shale having economic potential is usually one that is at or near enough to the surface to be developed by open-cast or conventional underground mining or by in-situ methods. The definition of shale oil in this article basically adopts the national standard "Shale Oil Geological Evaluation Method (GB/T 38718-2020)", that is shale oil refers to "oil that occurs in organic-rich shale series, the thickness of a single layer of siltstone, fine sandstone and carbonate rock is not more than 5 metres, and the cumulative thickness accounts for less than 30% of the total thickness of the shale series where there is no natural flow or the natural flow is less than the lower limit of industrial oil flows, an industrial oil flow can only be obtained by taking special technical measures" [41]. However, the standard does not clarify whether shale oil includes oil that has not yet existed in large quantities which can be obtained through underground in-situ cracking. Shale oil examined in this paper includes this kind of oil specifically. Therefore, there are obvious differences between oil shale and shale oil, but there are also some connections. The obvious difference is that oil shale is a shallow-buried organic solid mineral, while shale oil mostly refers to the liquid hydrocarbons in organic-rich shale, which may exist in various forms such as free, adsorbed and dissolved. The connections between oil shale and shale oil lie in that the liquid hydrocarbons obtained by in-situ cracking of deeply buried oil shale deposits are in-situ converted shale oil.

At present, the shale oil developed and produced in China mainly comes from two types of reservoirs, one is non-shale reservoirs (siltstone, fine-grained sandstone, and carbonate interlayers reservoirs), which is described as interlayer-type, the other is shale reservoirs (shale type). If only recoverable resources need to be calculated, the evaluation method based on the estimated ultimate recovery (EUR) of a single well can solve the problem. In this case, there is no need to focus on whether shale oil comes from interlayers or shale, and it is only necessary to determine the EUR from the results of comprehensive development. Moreover, shale oil resources may not be further classified. However, when evaluating the in-place resources of shale oil, it is necessary to distinguish between different types of shale oil resources and evaluate each type separately in a targeted manner to obtain results that are more consistent with the objective circumstances. The reason is that the occurrence states of shale oil in interlayers and shale differ greatly (the ineffective adsorbed hydrocarbons values vary greatly).

The interlayer-type shale oil (such as the shale oil in the Triassic Chang 7_3 Sub-member in the Ordos Basin and the Lucaogou Formation of the Jimsar Sag in the Junggar Basin) is similar to tight oil in terms of occurrence state and accumulation mechanism. Therefore, the volumetric method based on reservoir porosity is usually used to directly calculate the in-place resources of this type of shale oil. The occurrence state of shale-type shale oil (such as the shale oil in the Qingshankou Formation of the Gulong Sag in the northern Songliao Basin) is completely different from that of tight oil. There are large amounts of adsorbed hydrocarbons in shale pores. The preliminarily predicted proportion of adsorbed hydrocarbons in total hydrocarbons can reach 40–60% [42]. These adsorbed hydrocarbons cannot be converted into effective resources under the current technical conditions. Therefore, the in-place resources of this type of shale oil cannot be calculated directly using the volumetric method.

To assess the in-place resources of shale oil more objectively, it is necessary to classify shale oil resources based on occurrence state and accumulation mechanism. Considering the different occurrence states of interlayer-type and shale-type shale oil resources and according to the national standard applicable to the evaluation of shale oil resources, these resources are first classified into two types depending on reservoir lithology. Each reservoir is divided into siltstone, fine-grained sandstone, and carbonate interlayers. The shale oil in interlayers is classified as “interlayer shale oil” where the cumulative thickness of interlayers accounts for less than 30% of the total thickness of the shale formation and the thickness of a single layer is no more than 5 m (classified as tight oil where the single-layer thickness is greater than 5 m and the reservoir is tight, and otherwise classified as conventional oil). The shale oil in mudstone reservoirs is defined as “non-interlayer shale oil”. Additionally, although underground in-situ converted shale oil has not yet been developed and used, such shale oil has huge resource potential and will become a long-term strategic resource in the future [43]. For this reason, it is necessary to classify this kind of resource and evaluate separately so that necessary resource evaluation techniques can be prepared to serve medium- and long-term strategic planning. Therefore, in this paper, non-interlayer shale oil resources are further classified into pure shale oil ($Ro \geq 0.8\%$) and in-situ converted shale oil ($Ro < 0.8\%$) depending on the maturity of source rocks (Table 1).

Interlayer shale oil refers to the shale oil in siltstone, fine-grained sandstone, and carbonate reservoirs that generally occur as interlayers, interbeds, thin layers, or mixed sediment layers (for simplicity, these layers are collectively referred to as interlayers) and comply with the following provision in the national standard Geological Evaluating Methods for Shale Oil (GB/T 38718–2020): the cumulative thickness of interlayers should account for less than 30% of the total thickness of the shale formation, and the thickness of a single layer should be no more than 5 m. This type of shale oil is characterized by short-distance migration and accumulation.

Pure shale oil refers to the shale oil in shale reservoirs. Reservoir spaces are composed primarily of organic pores, lamellated fractures, and other types of fractures. This type of shale oil is mainly characterized by the retention and accumulation of hydrocarbons having not migrated.

In-situ converted shale oil refers to the hydrocarbons produced by the solid organic matter that has not been thermally decomposed and converted and needs to undergo an in-situ conversion process. In this process, the original viscous liquid hydrocarbons are lightened and condensed through large-scale in-situ heating and conversion, and with the pore-fracture network formed by associated organic pores, overpressure conditions, and gases, an effective new artificial displacement system is created to eventually obtain high-quality oil [43].

The classification of shale oil resources into interlayer shale oil, pure shale oil, and in-situ converted shale oil is favourable for the evaluation of such resources, the comparison of resource evaluation results, and the development of medium- and long-term plans for shale oil exploration.

Table 1. Classification of continental shale oil resources in China

Formation	Reservoir lithology	Single-layer thickness, Ro	Type	Typical examples
Organic-rich shale formation	Siltstone, fine-grained sandstone, and carbonate rock	Single-layer thickness ≥ 5 m	Tight oil (or conventional oil)	Chang 7_{1+2} Sub-members of the Triassic Yanchang Formation in the Ordos Basin
		The single-layer thickness is less than 5 m, the cumulative thickness of interlayers accounts for less than 30% of the total thickness of the shale formation	Interlayer shale oil	Chang 7_3 Sub-members of the Triassic Yanchang Formation in the Ordos Basin; the Lucaogou Formation of the Jimsar Sag in the Junggar Basin
	Shale	Ro ≥ 0.8%	Pure shale oil	The Qingshankou Formation of the Gulong Sag in the northern Songliao Basin
		Ro < 0.8%	In-situ converted shale oil	Medium- to low-maturity areas in Chang 7_3 Sub-members of the Triassic Yanchang Formation in the Ordos Basin

The methods for evaluating shale oil resources involve the classification and grading of these resources. First, as described above, shale oil resources are classified into three types: interlayer shale oil, pure shale oil, and in-situ converted shale oil. Because these three types of shale oil resources have significantly different occurrence states and generation characteristics, it is necessary to establish separate methods to evaluate these resources. Second, shale oil resources should be graded based on their geological and recoverable resources, and the corresponding evaluation methods should be established.

4.1. Methods for evaluating interlayer shale oil resources

4.1.1. Methods for evaluating the in-place resources of interlayer shale oil

Considering the current status of shale oil exploration in China, the volumetric method based on reservoir porosity is suitable for evaluating the in-place resources of interlayer shale oil. Based on different exploration stages for different areas and formations, the evaluation methods are classified into the Monte Carlo method and the small panel method [44, 45].

4.1.1.1. Volumetric method based on reservoir porosity-Monte Carlo method

The method is suitable for areas or formations with low extents of exploration degree and limited data which focuses on addressing the uncertainty in the distribution of evaluation parameters. Generally, it is required that the calculated results ratio of P10 (an estimate with a 10% probability) to P90 (an estimate with a 90% probability) be greater than 3. Otherwise, the uncertainty associated with low extents of exploration cannot be fully reflected.

The calculation formula is as follows:

$$Q_{in\text{-}place} = 100 \cdot (1 - S_w) \cdot H \cdot A \cdot ø \cdot \rho \cdot (1/B_o), \tag{1}$$

where $Q_{in\text{-}place}$ is the in-place resource of shale oil, 10^4 t; S_w is the average water saturation of the reservoir, decimal; H is the average effective thickness, m; A is the shale oil-bearing area, km^2; $ø$ is the average effective porosity, decimal; ρ is the average density of crude oil, t/m^3; and B_o is the average volume factor of crude oil, m^3/m^3.

For average water saturation, shale oil-bearing area, average effective thickness, and average effective porosity, three values (i.e., minimum value, possible value, and maximum value) need to be given to construct the triangular distribution of the listed parameters. Then, the Monte Carlo method should be employed for random sampling, and the in-place resources are calculated (probability distribution curve). The main parameters used in this method include average water saturation, shale oil-bearing area, effective shale thickness, and effective shale porosity, and the core process is the random sampling and simulation by the Monte Carlo method.

4.1.1.2. Volumetric method based on reservoir porosity-small panel method

The volumetric-small panel method is suitable for areas or formations with medium to high extent of exploration and abundant data. This method focuses on addressing the uneven distribution of geological parameters on a 2D plane. The spatial interpolation method is used to reflect the heterogeneity of the distribution of geological parameters on a plane. The evaluation process is described below. First, 2D contour maps are created based on the exploration data. Second, the evaluation area is divided into "n" number of evaluation units (panels), and interpolation (assignment of values) is performed on the geological parameters of each evaluation panel using a spatial interpolation algorithm. Third, the in-place resources of each evaluation panel are calculated. Finally, the resources of all evaluation panels are added up to get the total in-place resources result in the evaluation area.

The calculation formula is as follows:

$$Q_{in\text{-}place} = \sum_{i=1}^{n} (100 \cdot S_{o-i} \cdot H_i \cdot A_i \cdot \o_i \cdot \rho_o / B_o), \tag{2}$$

where $Q_{in\text{-}place}$ is the in-place resources of shale oil, 10^4 t; n is the number of evaluation panels in the evaluation area; S_{o-i} is the oil saturation of the i^{th} evaluation panel, decimal; H_i is the effective thickness of the i^{th} evaluation panel, m; A_i is the oil-bearing area of the i^{th} evaluation panel, km^2; $\o_i$ is the average effective porosity of the i^{th} evaluation panel, decimal; ρ_o is the density of crude oil, t/m^3; and B_o is the volume factor of crude oil, m^3/m^3.

The key process of this method is the drawing of a 2D contour map for various geological parameters, and the core algorithms are the 2D spatial data fitting and interpolation algorithms, such as the finite element method and the Kriging interpolation method.

4.1.2. Methods for evaluating the recoverable resources of interlayer shale oil

Given the fact that the number of shale oil production wells operating in China at present is very small, the recovery factor statistical method and the EUR analogy method are suitable for evaluating the recoverable resources of interlayer shale oil. The EUR means the estimated ultimate recovery from a single production well determined through evaluation based on the production curves of the well.

4.1.2.1. EUR analogy method

In areas with relatively large numbers of production wells, the EUR analogy method [44, 45] can be used. The evaluation process is described below. The first step is to estimate the possible average well drainage area in the evaluation area. The second step is to estimate the number of drillable wells in the evaluation area. The third step is to estimate the drilling success rate and the number of successful wells in the evaluation area. The fourth step is to obtain the average EUR of successful wells by analogy. The fifth step is to calculate the recoverable resources of shale oil in the evaluation area.

The calculation formula is as follows:

$$Q_{rc} = R \cdot P \cdot A/D, \tag{3}$$

where Q_{rc} is the recoverable resources of shale oil, 10^4 t; R is the average EUR of production wells, 10^4 t; P is drilling success rate, decimal; A is the effective area of the evaluation area, km^2; and D is the average well drainage area, km^2.

The key parameters in the formula, such as the average EUR of production wells, are usually provided in the form of parameter distribution. The Monte Carlo random simulation method is used to calculate the final result.

4.1.2.2. Recovery factor statistical method

In areas with no or few production wells, the recovery factor statistical method should be used. The calculation formula is as follows:

$$Q_{rc} = Q_{in\text{-}place} \cdot k_{rc}, \tag{4}$$

where Q_{rc} is the recoverable resource of shale oil, 10^4 t; $Q_{in\text{-}place}$ is the in-place resources of shale oil, 10^4 t; and k_{rc} is the shale oil recovery factor, decimal.

The recovery factor, which is a key parameter in the formula, is usually obtained from the statistics of shale oil production areas with similar or close geological conditions. The minimum, possible, and maximum values of the recovery factor are first obtained from statistical data and are then used to construct a triangular distribution. The recoverable resources are calculated using the Monte Carlo random simulation method.

4.2. Methods for evaluating pure shale oil resources

4.2.1. Methods for evaluating the in-place resources of pure shale oil

Pure shale oil occurs in the pore spaces of shales (including lamellated and other types of fractures). In several studies it is believed that the adsorbed oil in fractures and pores cannot be effectively extracted, and only movable oil can be considered in-place resources [42, 46, 47]. Therefore, the volumetric method based on the content of S1 is the main method used to evaluate the in-place resources of pure shale oil in China. Other similar methods include the volumetric methods based on the content of chloroform asphalt “A” and the difference method using oil generation quantity and oil expulsion quantity obtained by the basin modelling technique.

According to the varying extents of exploration in different areas and formations, the volumetric methods based on the content of thermally decomposable hydrocarbons can be classified into the Monte Carlo method and the small panel method.

4.2.1.1. Volumetric method based on the content of thermally decomposable hydrocarbons-Monte Carlo method

This method is suitable for areas or formations with low extents of exploration and limited S1 data. The calculation formula is as follows:

$$Q_{in\text{-}place} = 0.1 \cdot A \cdot H \cdot \rho_{rock} \cdot S_1 \cdot k_{S_1}, \tag{5}$$

where $Q_{in\text{-}place}$ is the in-place resources of shale oil, 10^4 t; A is the effective area of shale, km^2; H is the average effective thickness of shale, m; ρ_{rock} is the density of shale, t/m^3; S_1 is the content of thermally decomposable free hydrocarbons in shale, mg/g; and k_{S1} is the light hydrocarbon recovery coefficient, which is greater than 1 and is dimensionless.

For the effective area of shale, average effective thickness of shale, content of thermally decomposable free hydrocarbons in shale, and light hydrocarbon recovery coefficient, three values (minimum value, possible value, and maximum value) need to be given to construct the triangular distribution of these four parameters. Furthermore, the Monte Carlo method should be used for random sampling, and then the in-place resources of shale oil can be calculated.

4.2.1.2. Volumetric method based on the content of thermally decomposable hydrocarbons-small panel method

This method is suitable for areas or formations with medium to high extents of exploration and abundant S1 data. Based on the exploration data, 2D contour maps are created for various parameters, including the effective area of shale, average effective thickness of shale, content of thermally decomposable free hydrocarbons in shale, and the light hydrocarbon recovery coefficient. Additionally, the evaluation area is divided into "n" number of evaluation units (panels), and interpolation (assignment of values) is performed on the geological parameters of each evaluation panel using a spatial interpolation algorithm. Then, the in-place resources of each evaluation panel are calculated. Finally, the resources of all evaluation panels are added up to get the total in-place resources result in the evaluation area. The calculation formula is as follows:

$$Q_{in\text{-}place} = \sum_{i=1}^{n} (0.1 \cdot A_i \cdot H_i \cdot A_i \cdot \rho_{rock} \cdot S_{1-i} \cdot k_{S_{1-i}}), \tag{6}$$

where $Q_{in\text{-}place}$ is the geological resources of shale oil, 10^4 t; n is the number of evaluation panels in the evaluation area; A_i is the oil-bearing area of the i^{th} evaluation panel, km^2; H_i is the effective thickness of the i^{th} evaluation panel, m; ρ_{rock} is shale density, t/m^3; S_{1-i} is the content of thermally decomposable free hydrocarbons in shale of the i^{th} evaluation panel, mg/g; and k_{S1-i} is the light hydrocarbon recovery coefficient of the i^{th} evaluation panel (which is greater than 1 and is dimensionless).

4.2.2. Methods for evaluating the recoverable reserves of pure shale oil

The methods for evaluating the recoverable resources of pure shale oil are the same as those used for interlayer shale oil. Therefore, the details of these methods are not included herein.

4.3. Discussion on the methods for evaluating in-situ converted shale oil resources

The quantity of in-situ converted shale oil refers to the number of hydrocarbons converted from kerogens during the in-situ heating of medium- to low-maturity shales. In the in-situ conversion process (which mainly involves heating), shales will continue to generate hydrocarbons when heated. The quantity of generated hydrocarbons depends on the following two factors: 1) the current hydrocarbon generation potential ($I_{\mathrm{H,pd}}$) of shales, i.e. the hydrogen index, and 2) the residual hydrocarbon generation potential ($I_{\mathrm{H,end}}$) of organic matter after heating, i.e. the residual hydrogen index.

According to the theory of hydrocarbon generation and chemical kinetic parameters, the quantities of hydrocarbons generated in the conversion process are calculated as follows:

$$\begin{cases} Q_{HC} = 10^{-5} \cdot A \cdot h \cdot \rho_{rock} \cdot TOC \cdot (I_{H,pd} - I_{H,end}) \\ Q_{oil} = Q_{HC} \cdot p_{oil} \\ Q_{gas} = Q_{HC} \cdot (1 - p_{oil}) \end{cases} \tag{7}$$

The calculation formula of total hydrocarbons is as follows:

$$\begin{cases} Q_{HC} = 10^{-5} \cdot A \cdot h \cdot \rho_{rock} \cdot TOC \cdot (S_1 + I_{H,pd} - I_{H,end}) \\ Q_{oil} = Q_{HC} \cdot p_{oil} \\ Q_{gas} = Q_{HC} \cdot (1 - p_{oil}) \end{cases} \tag{8}$$

The recoverable resources (M_{HC}) of in-situ converted shale oil are calculated by multiplying the quantity of generated hydrocarbons (Q_{HC}) with the recovery factor (k_{rc}):

$$M_{HC} = Q_{HC} \cdot K_{rc}. \tag{9}$$

If the oil and gas recovery factors can be obtained from field pilot tests, the recoverable reserves of oil and gas can be calculated accordingly.

In formulas (7)–(9), $I_{\mathrm{H,pd}}$ is the current hydrogen index of organic matter, mg/g; $I_{\mathrm{H,end}}$ is the hydrogen index of residual organic matter after heating, mg/g; Q_{HC}, Q_{oil}, and Q_{gas} are the quantities of hydrocarbons, oil, and gas (calculated by oil equivalent) generated by in-situ converted shale, respectively, 10^8 t; S_1 is the content of thermally decomposable free hydrocarbons in in-situ converted shale before heating, mg/g; A is the area of shale, km^2; h is the thickness of shale, m; ρ_{rock} is the density of shale, t/m^3; TOC is the weight percentage of total organic carbon in shale, decimal; P_{oil} is the proportion of converted hydrocarbons in the liquid state in the total hydrocarbons (calculated by oil equivalent), decimal; M_{HC} is the recoverable resources of in-situ converted shale oil (calculated by oil equivalent), 10^8 t; and k_{rc} is the recovery factor for in-situ converted shale oil, decimal.

In-situ converted shale oil has a lower degree of thermal maturity (Ro < 0.8%), hence S_1 added but a very small portion of the hydrocarbon potential of in-situ shale oils. In the actual operation, only the difference in hydrocarbon index between the quantities of hydrocarbons generated before and after heating was considered, as shown in Formula (7).

5. Potentials of various types of shale oil resources in China

5.1. Key evaluation parameters and criteria

The determination of the key parameters and criteria for evaluating shale oil resources and the lower limits of these parameters is currently a major difficulty in the respective evaluation process. At present, there are no relevant standards at the national, industrial, and enterprise levels. In this study, the key parameters and criteria are determined based on the values of evaluation parameters used in oilfields, experimental statistics, and the previous research results for reference.

5.1.1. Key parameters and criteria for the evaluation of pure shale oil and interlayer shale oil

5.1.1.1. Pure shale oil

Formulas (5) and (6) for calculating the in-place resources of pure shale oil in different exploration stages reveal that the content of S1 and the volume of shale are the key parameters. When the value of the evaluation area is fixed, the thickness of shale becomes a key parameter. When it is difficult to draw a planar distribution map for the S1 content in the evaluation area, the said content can be calculated from TOC and Ro before the corresponding distribution map is created. Therefore, in this case, TOC, Ro, and the thickness of shale are the key parameters for evaluating the in-place resources of pure shale oil. The lower limits of various parameters determined taking into account the factors described below are listed in Table 2. The lower limit of S1 content was set to 2.0 mg/g based on the values given or proposed by some scholars. In 2018, Huang et al. [48] set the limit value of S1 (light hydrocarbon loss has not been recovered) to 1.0 mg/g boundary for ineffective and low-efficiency resources. Zhao et al. [23] proposed to set the limit value of S1 (light hydrocarbon loss has not been recovered) to 2 mg/g or, as the best option, to 4–6 mg/g with respect to the quantity of retained hydrocarbons in economic shale oil. The lower limit of the thickness of shale was set to 5 m taking into account the minimum thickness required for hydraulic fracturing of horizontal wells in accordance with the national standard Geological Evaluating Methods for Shale Oil [42]. In the absence of a planar distribution map for the S1 content, the lower limit of TOC was set to 2.0% based on the three considerations described below. First, Lu et al. [49] studied the relationship between S1 and TOC of the mature source rocks in the Qingshankou Formation in the southern Songliao Basin and recommended that TOC ≥ 2.0% be used as the lower limit for hydrocarbon accumulation. Second, in 2011, Zhang [50] set the lower limit of TOC in the core area of marine shale gas to 2.0% based on the TOC and Ro of shale taking into account various factors, such as the distribution conditions and preservation conditions. Third, the experimental data on the TOC and hydrogen index of shales in the First Member of the Qingshankou Formation in the northern Songliao Basin (Fig. 5) shows that TOC = 2.0% is the critical point for changes in the hydrogen index. In the same situation, the lower limit of Ro was set to 0.8% based on the relationship between the hydrogen index and Ro (Fig. 6) established by the authors of this paper using the hydrocarbon generation potential model [51, 52] and 395 measurement datasets of shales in the Chang 7 Member in the Ordos Basin. It can be seen from Figure 6 that the average original hydrogen index is 700 mg/g (Ro ≤ 0.5%); when Ro is 0.75%, the corresponding residual hydrogen index is 656 mg/g, so the effective carbon conversion rate ((original hydrogen index – residual hydrogen index)/original hydrogen index × 100%) is 6.22%. Similarly, the calculated effective carbon conversion rate is 18.44% when Ro is 0.8%, and 76.12% when Ro is 1.0%. Therefore, if the lower limit of Ro is set to 0.75% (as preliminarily determined by the Gulong Sag Shale Oil Research Team of Daqing Oilfield), this value will be excessively low because the organic matter has not been converted into hydrocarbons in large quantities. By contrast, if the lower limit of Ro is set to 1.0% (according to Zhao et al. [53]), this value will be too high because the effective carbon conversion rate has far exceeded 50%. Considering the trend of change in the effective carbon conversion rate with the Ro value, it is more appropriate to set the lower limit of Ro to 0.8%.

5.1.1.2. Interlayer shale oil

From Formulas (1) and (2) for calculating the in-place resources of interlayer shale oil using the volumetric method based on reservoir porosity in different exploration stages, it can be seen that the interlayer (reservoir) thickness, porosity, and oil saturation ($1-S_w$) are the key parameters. Considering the factors described below, the lower limits of these parameters were set as follows. The cumulative thickness of intervals with concentrated interlayers was set to ≥ 5 m, average porosity to ≥ 4%, and oil saturation to ≥ 30% (Table 2). The lower limit of the cumulative thickness of intervals with concentrated

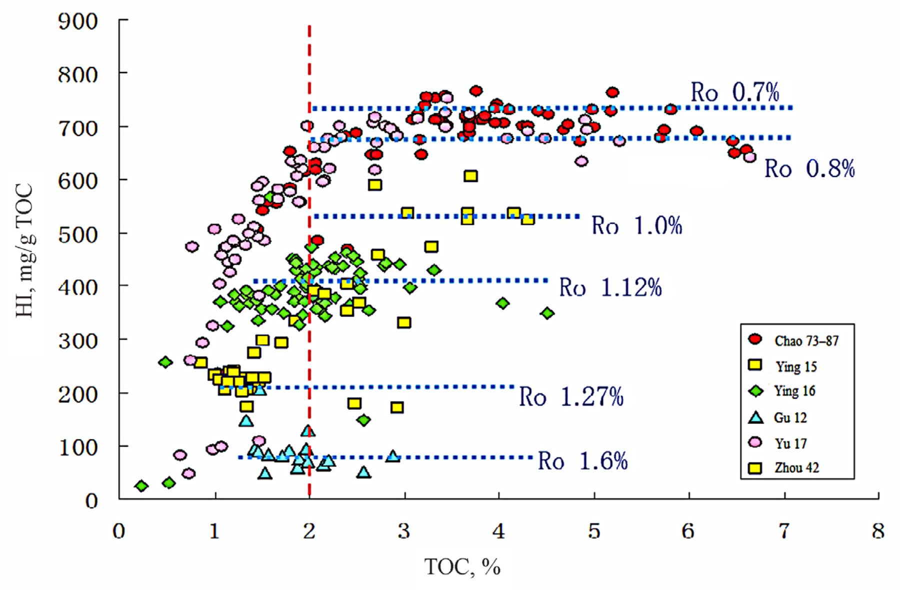

Fig. 5. Relationship between the total organic carbon and hydrogen index of shales in the First Member of the Qingshankou Formation in the northern Songliao Basin.

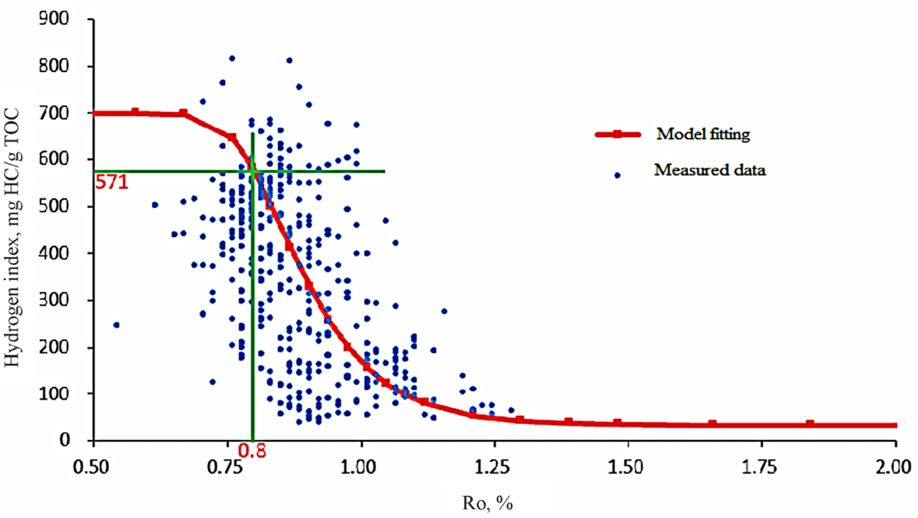

Fig. 6. Relationship between the hydrogen index $I_{H,pd}$ and Ro of shales in the Chang 7 Member of the Yanchang Formation in the evaluation area of the Ordos Basin.

interlayers was set to 5 m considering the minimum thickness required for hydraulic fracturing of existing horizontal wells. The lower limit of average interlayer porosity was set to 4% based on the two considerations detailed below. First, the statistics made by Qiu et al. [54] show that the porosity of tight oil-bearing reservoirs in the Lucaogou Formation of the Jimsar Sag in the Junggar Basin primarily ranges between 4% and 16%, and the researchers set its lower limit to 4%. Second, based on the actual trial production data, Changqing Oilfield, Xinjiang Oilfield, and Tuha Oilfield set the lower limit of porosity to 4–5% (Table 3) for the tight sandstone reservoirs in the Ordos Basin, tight reservoirs composed of mixed sediments in the Jimsar Sag, and Class III tight tuff reservoirs in the Santanghu Basin during field production. The lower limit of oil saturation was set to 30% based on a large quantity of laboratory statistics with respect to oil saturation and oil-bearing grade. According to these statistics, the oil saturation of the fluorescence grade is typically lower than 30%, that of the oil trace grade ranges between 30% and 50%, and that of the oil spot grade and higher grades is higher than 50%.

Third, in real formations, sometimes the thickness of an interlayer or a shale layer is less than 5 m, but the combined thickness of the two layers is greater than 5 m. In such cases, the lower limit of thickness should be changed to the combined thickness of these two layers, which is greater than 5 m (Table 2).

Table 2. Lower limits of key parameters for the evaluation of pure shale oil and interlayer shale oil

Type of shale oil	Lower limits of key evaluation parameters	
Pure shale oil	No planar distribution map for the S1 content	When a planar distribution map for the S1 content is available
	TOC ≥ 2.0%	S1 > 2.0 mg/g (S1, light hydrocarbon loss has been recovered)
	Ro ≥ 0.8%	
	Shale thickness ≥ 5 m	Shale thickness ≥ 5 m
Interlayer shale oil	Interlayer thickness ≥ 5 m	
	Average porosity ≥ 4%	
	Oil saturation ≥ 30%	
Shale + interlayer	Shale layer	Interlayer
	TOC ≥ 2.0%	Average porosity ≥ 4%
	Ro ≥ 0.8%	Oil saturation ≥ 30%
	Shale thickness + interlayer thickness ≥ 5 m	

Table 3. Criteria for the classification of interlayer shale oil reservoirs in actual production adopted by oilfield companies

Oilfield company	Basin	Formation	Lithology	Reservoir conditions		Reservoir class		
						Class I	Class II	Class III
Changqing Oilfield	Ordos Basin	Chang 7_3 Sub-member	Sandstone	Reservoir parameters	Porosity, %	> 10	10–6	**6–4**
					Permeability, 10^{-3} μm^2	1–0.2	0.2–0.05	0.05–0.02
					Reservoir thickness, m	> 15	15–6	6–4
					Oil saturation, %	> 70	70–50	≤ 50
Xinjiang Oilfield	Junggar Basin	Lucaogou Formation	Mixed sediments	Reservoir parameters	Porosity, %	> 12	12–8	**8–5**
					Permeability, 10^{-3} μm^2	≥ 0.01	0.01–0.005	< 0.005
					Reservoir thickness, m	> 25	25–10	10–7
					Oil saturation, %	> 50	50–30	< 30
Tuha Oilfield	Santanghu Basin	Tiaohu Formation	Tuff	Reservoir parameters	Porosity, %	> 18	18–8	**< 8–4**
					Permeability, 10^{-3} μm^2	> 0.1	0.1–0.01	< 0.01
					Reservoir thickness, m	> 15	15–10	10–5
					Oil saturation, %	> 70	70–50	< 50

5.1.2. Key parameters for the evaluation of in-situ converted shale oil resources

5.1.2.1. Hydrogen index of residual organic matter after heating

In this study, the Chang 7_3 Sub-member in the Ordos Basin is taken as an example. The results of in-situ conversion simulation experiments conducted on three shale samples show that the residual hydrocarbon generation potentials ($I_{\mathrm{H,end}}$) of organic matter after heating are 126.33 mg/g, 79.92 mg/g, and 197.78 mg/g, respectively, with an average of 134.67 mg/g (Table 4). Based on these results, we can determine that the residual hydrocarbon generation potential primarily ranges between 79.9 mg/g and 197.8 mg/g.

Table 4. Thermal simulation results for shale samples from the Chang 7_3 Sub-member of the Yanchang Formation in the Ordos Basin (1)

Sample	TOC, %	S1, mg/g	S2, mg/g	Ro, %	Total production, kg/t	Oil generation, kg/t
38–1	23.70	4.06	79.88	0.8	54	36
LI 38–2	23.70	4.06	79.88	0.8	65	47
HJF-out	24.73	6.29	115.62	0.5	73	52
Average value	24.04	4.80	91.79	0.7	64	45

Table 4. Thermal simulation results for shale samples from the Chang 7_3 Sub-member of the Yanchang Formation in the Ordos Basin (2)

Sample	Gas generation, m^3/t	Oil/total equivalent resources, %	Residual S2, mg/g	$I_{H,pd}$, mg/g	$I_{H,end}$, mg/g
38–1	22.50	66.67	29.94	337.05	126.33
LI 38–2	22.50	72.31	18.94	337.05	79.92
HJF-out	26.00	71.23	48.91	467.53	197.78
Average value	23.67	70.07	32.60	380.54	134.67

5.1.2.2. Gas-oil ratio

Gas-oil ratio is related to the heating process. The longer the heating time and the higher the temperature, the greater the proportion of gas and the lesser the proportion of oil. According to the experimental results for the three samples taken from the Chang 7_3 Sub-member of the Yanchang Formation in the Ordos Basin, the proportions of oil in the total equivalent resources are 66.67%, 72.31%, and 71.23%, respectively, with an average of 70.07% (Table 4). In other words, the GOR is approximately 7:3.

5.1.2.3. Recovery factor

The recovery factor is closely related to the implemented measures. A long heating time and a high temperature are beneficial for the mobility and recovery of oil and gas. When the average formation temperature is higher than 330 °C, the shale oil mainly exists in the gaseous state. The recovery factor value used in this paper is chiefly determined based on the empirical values obtained through communication with international oil companies. The recovery factors determined by foreign companies through experiments range between 60% and 70%. The average value, which is 65%, is used in this study.

5.1.2.4. Hydrocarbon generation potential chart

To identify the statistically significant relationship between the hydrogen index ($I_{H,pd}$) and Ro, it is necessary to determine the parameters of the hydrocarbon generation potential model and then create fitted curves. Based on 395 measurement datasets of the evaluation area in the Ordos Basin, the authors made a hydrocarbon generation potential chart for the shales in the Chang 7_3 Sub-member (Fig. 6).

5.2. Potential of continental shale oil resources in China

5.2.1. Evaluation of the resource potential of shale oil in typical formations

The shale oil resources in the typical formations of three basins (which are the hot spots for the exploration of continental shale oil in China) were classified and evaluated using the aforementioned evaluation methods based on the key evaluation parameters and their lower limits criteria. In the Ordos Basin, the Chang 7_3 Sub-member of the Yanchang Formation was selected as the target of evaluation, and the in-place resources of three types of shale oil, namely, interlayer shale oil, pure shale oil, and in-situ converted shale oil, were assessed separately. In the northern Songliao Basin, the Qingshankou Formation and the Nenjiang Formation were selected as the targets of evaluation. In the Jimsar Sag of the Junggar Basin, the Lucaogou Formation was selected as the target of evaluation. The detailed evaluation results are given in Table 5.

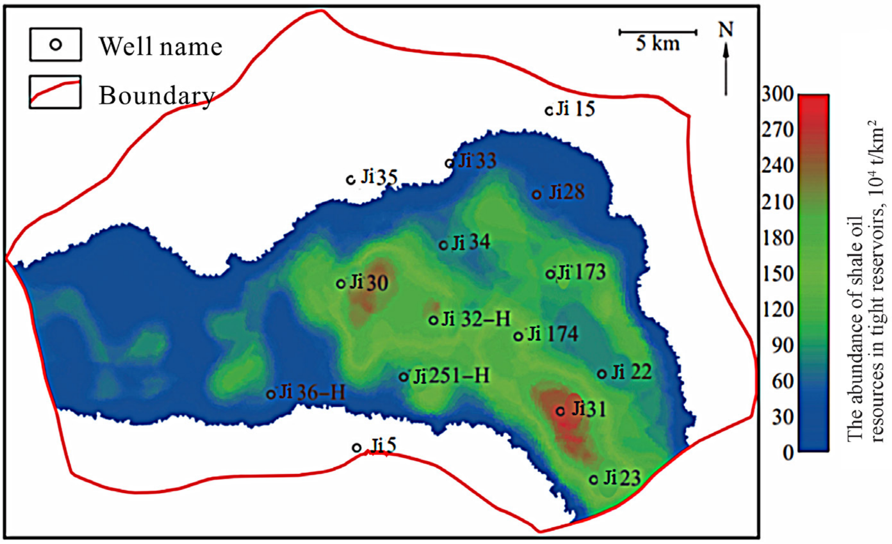

Fig. 7. Spatial distribution map of the "upper sweet spot" in the Lucaogou Formation of the Jimsar Sag of the Junggar Basin.

The data in Table 5 shows that, first, resource abundance and unit resource factor are related to the type of the resource, and the values of these two parameters are the highest in the case of in-situ converted shale oil, the lowest in the case of pure shale oil, and moderate in the case of interlayer shale oil, indicating that the in-situ converted shale oil has long-term strategic significance. Second, resource abundance and unit resource factor vary from basin to basin, their values are the highest in the Jimsar Sag of the Junggar Basin, the lowest in the Ordos Basin, and moderate in the northern Songliao Basin, indicating that the quantity of shale oil in the Jimsar Sag is “small yet abundant”. And, third, the in-place resources of shale oil are the greatest in the Ordos Basin, moderate in the northern Songliao Basin, and the smallest in the Jimsar Sag of the Junggar Basin, showing that the Ordos Basin and the northern Songliao Basin are currently the most important areas with great potential in terms of shale oil resources in China.

5.2.2. Results of the evaluation of the resource potential of shale oil in China

The potentials of three types of shale oil in the shale formations in the main basins in China were evaluated using the same methods and practices as those used for the evaluation of shale oil in typical formations. The evaluation results show that the in-place resource of pure shale oil is 145.4×10^8 t, with a recoverable resource of 9.4×10^8 t; the in-place resource of interlayer shale oil is 95.1×10^8 t, with a recoverable resource of 7.1×10^8 t; and the in-place resource of in-situ converted shale oil is 708.2×10^8 t, with a recoverable resource of 460.3×10^8 t (Table 6).

5.2.3. Economic analysis of shale oil resources in China

The economic benefits of different types of shale oil vary greatly.

5.2.3.1. Interlayer shale oil

The large-scale development of shale oil in the Lucaogou Formation in the Junggar Basin has revealed the quasi-economic value of interlayer shale oil. Interlayer shale oil is currently not cost-effective, but with continuous innovations and the advancement of production technologies, it will soon generate economic benefits.

5.2.3.2. Pure shale oil

The breakthroughs with respect to the shale oil (Gulong Sag shale oil) in the Qingshankou Formation in the northern Songliao Basin have demonstrated that pure shale oil with a high degree of thermal evolution ($Ro > 1.2\%$) and a high gas content ($GOR > 500$) has also great economic values. However, the degree of thermal evolution ($Ro < 1.0\%$) and GOR of continental pure shale oil in China are generally low. For this reason, most of continental pure shale oil is not economically recoverable at present.

Table 5. Resource potential of continental shale oil in typical formations in China

Region	Formation	Type of shale oil	Area, km^2	Average thickness, m	Resource abundance, 10^4 t/km^2	Unit resource factor, 10^4 t/km^2·m	In-place resources, 10^8 t
Ordos Basin	Chang 7_3 Sub-member of the Yanchang Formation	Interlayer shale oil	17006	8.3	16.3	1.96	27.73
		Pure shale oil	24724	32.6	15.8	0.48	39.07
		In-situ converted shale oil	16932	27.8	204.2	7.35	345.80
Northern Songliao Basin	First Member of the Qingshankou Formation	Interlayer shale oil	650	8.0	48.5	6.06	3.15
	Second Member of the Qingshankou Formation	Interlayer shale oil	840	25.0	66.2	2.65	5.56
	First Member of the Qingshankou Formation	Pure shale oil	14481	34.3	36.1	1.05	52.23
	Nenjiang Formation	In-situ converted shale oil	8166	47.7	323.2	6.8	263.90
Jimsar Sag of the Junggar Basin	Lucaogou Formation	Interlayer (upper sweet spot)	518	12.7	92.5	7.28	4.79
		Interlayer shale oil (lower sweet spot)	910	14.5	79.1	5.46	7.20
		Pure shale oil	828	204.7	43.8	0.21	3.63
		In-situ converted shale oil	516	12.5	126	10.08	6.50

Note: The definition of resources given in the standard Classifications for Petroleum Resources and Reserves (GB/T 19492–2004) is used in this study (the same below).

5.2.3.3. In-situ converted shale oil

Although plenty of research and many pilot production tests have been conducted domestically and internationally [53, 55], there is currently no drilling and production scheme that can be put into practice in China. Given the current technical level, these resources are not yet economically recoverable. In the next 5 to 10 years, they may become economically recoverable after major breakthroughs in science and technology are made.

Table 6. Resource potential of continental shale oil in China

Type	Basin/Formation	In-place resources, 10^8 t	Recoverable resources, 10^8 t	Recovery factor, %	Economic analysis
Pure shale oil	Ordos Basin/Chang 7_3 Sub-member	39.1	2.0	5	Except for the shale oil with a high degree of thermal evolution and a high gas content in the Qingshankou Formation, the shale oil in other areas is not yet economically recoverable at present
	Northern Songliao Basin/First Member of the Qingshankou Formation	52.2	4.7	9	
	Junggar Basin/Lucaogou Formation	3.6	0.2	5	
	Other formations	50.5	2.5	5	
	Total	145.4	9.4	6.5	
Interlayer shale oil	Ordos Basin/Chang 7_3 Sub-member	27.7	2.2	8	Formations where shale oil resources are relatively concentrated have preliminary economic value
	Northern Songliao Basin/First and Second Members of the Qingshankou Formation	8.7	0.6	7	
	Junggar Basin/Lucaogou Formation	12.0	1	8	
	Other formations	46.7	3.3	7	
	Total	95.1	7.1	7.5	
In-situ converted shale oil	Ordos Basin/Chang 7_3 Sub-member	345.8	224.8	65	In the next 5 to 10 years, these resources may become economically recoverable after major breakthroughs in science and technology are made
	Northern Songliao Basin/Nenjiang Formation	263.9	171.5	65	
	Junggar Basin/Lucaogou Formation	6.5	4.2	64	
	Other formations	92.0	59.8	65	
	Total	708.2	460.3	65	

6. Conclusions

1. The shale oil resources in China are classified into three types: interlayer shale oil (including shale oil in interlayers, thin layers, and mixed sedimentary rocks), pure shale oil, and in-situ converted shale oil. This classification provides an important reference for unifying the research, evaluation, and comparison methods for shale oil resources in China.
2. The methods and quantitative models for evaluating pure shale oil, interlayer shale oil, and in-situ converted shale oil in different exploration stages are proposed to address the inconsistency and irrationality of shale oil evaluation methods, thus providing an important reference for evaluating various types of shale oil resources.
3. The key parameters for evaluating shale oil resources and their lower limits determined in this study provide a basis and reference for screening and determining the evaluation areas for various types of shale oil and the scope of evaluation.
4. Using the methods for classifying and evaluating shale oil resources and the set of evaluation parameters and criteria proposed in this paper, the shale oil resources were evaluated in typical shale formations in China, including the Yanchang Formation in the Ordos Basin and shale formations in the northern Songliao Basin and the Jimsar Sag of the Junggar Basin. The evaluation results are consistent with the actual conditions revealed by exploration practices, thus verifying the practicability of the proposed system of evaluation methods.
5. The evaluation results with respect to the typical shale formations in several major basins in China show that the in-place resource of pure shale oil in China is 145.4×10^8 t, with a recoverable resource of 9.4×10^8 t; the in-place resource of interlayer shale oil is 95.1×10^8 t, with a recoverable resource of 7.1×10^8 t; and the in-place resource of in-situ converted shale oil is 708.2×10^8 t, with a recoverable resource of 460.3×10^8 t. These results demonstrate that the continental shale oil in China has tremendous resource potential and medium- to long-term strategic significance.

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