Origin and Genesis of the Permain Hydrocarbon in the Northeast of the Dongdaohaizi Depression, Junggar Basin, China

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ABSTRACT: Dongdaohaizi area is an important hydrocarbon-rich depression in the Junggar Basin. Early resource evaluation has revealed that it has superior hydrocarbon generation conditions. No major exploration breakthrough has been observed in the hydrocarbon from the Permian Pingdiquan Formation source rocks, which are widely distributed and have a large sedimentary thickness. The unclear recognition of the genesis, the sources, and the hydrocarbon evolution history of the formation seriously restricted further exploration and development. Sixty-four samples were acquired during the study, consisting of 30 source rocks, 13 crude oil samples, and 21 natural gas samples. Studying the geochemical characteristics of the source rock extract and the surrounding structural crude oil in the Dongdaohaizi Depression, the differences in the stable carbon isotope, the biomarker compound, and the molecular relative composition of the three sets of main source rock products in the research fields are summarized. The results reflect that the drying coefficient of natural gas in the study area is generally low, and the fractional distillation value of methane and ethane is 0.32, which is most likely due to the loss of oil and gas migration and the mixing of different types of natural gases. The carbon isotope value is relatively low, with the Pr/Ph being generally less than 3.0. The content of sterane C_{29} is the highest in the relative composition of steranes, followed by the content of sterane C_{28}, which together account for more than 80% of the total sterane content, and then followed by a lower content of C_{27} sterane, accounting for only 5−20% of the total content, which generally conforms to the characteristics of Permian Pingdiquan Formation source rock products. The carbon isotope value of crude oil ranges from −30.94 to −28.31‰, which is different from the characteristics of typical Permian source rocks (values range from −34.49 to −28.21‰), while it is related to typical Carboniferous products (values range from −29.98 to −24.1‰), indicating that small amounts of Carboniferous source rock products were mixed in different degrees in the Dinan fault area. According to the distribution law of oil and gas, the geochemical characteristics and hydrocarbon sources were considered the oil source in the east of the Dongdaohaizi Depression, mainly from the source rocks of the Permian Pingdiquan Formation. The products of the peak period of hydrocarbon generation in the source rocks of the Pingdiquan Formation have not been transported to the high structural positions on a large scale to form reservoirs. They may still exist in the deep part of the Depression and the slope area. The low-amplitude structural and lithologic traps in the slope area of the Dongdahaizi Depression are promising targets for finding the products of the peak period of hydrocarbon generation. This is of great significance to reveal the Permain hydrocarbon evolution in the Junggar Basin and guide further research on the oil-source correlation of natural gas from the paleo-strata.

1. INTRODUCTION

The Junggar Basin is rich in oil and gas resources and is one of the major large oil-bearing basins contributing to China’s oil and gas resources. After decades of exploration and research, great progress has been made. The Kelameili gas field, the Jurassic oil and gas reservoir in the L1 well area, the Cretaceous oil and gas reservoir in the Ln6 well area, the Cretaceous oil and gas reservoir in the Dx9 well area, the Jurassic oil and gas reservoir in the D20 well area and the D12 well area have been found in the Dinan uplift located at the periphery of the work area. The Caiyao Oil Field has been found in the Baijiahai uplift, in the Fubei slope area, showing abundant hydrocarbon characteristics. All of these reflect the abundance of oil and gas exploration prospects in the work area. The Dongdaohaizi Depression, located in the center of the Junggar Basin, has experienced many years of exploration and has been proved to have good source rock conditions. Well DN8, which was drilled in the Northeast of the Dongdaohaizi
Depression in 2013, obtained high-yield industrial oil flow in the Permian Wutonggou Formation, indicating that the Dongdahaizi Depression is a hydrocarbon-rich depression with great hydrocarbon generation and expulsion capacity. Many oil and gas reservoirs are found around the Dongdahaizi Depression, surrounded by the Dongdahaizi Depression, the Dishuiquan Depression, and the Wucaiwan Depression. The Mobei Oil Field with a relatively large hydrocarbon scale should come from the west of the Pen1 Depression. The Kelameili Gas Field should come from the north of the Dishuiquan Depression. Where was the large amount of oil and gas resources produced by the Dongdahaizi Depression?

This research will prove helpful to determine the hydrocarbon source of the Permian strata in the Dongdahaizi Depression and lay the foundation for the development potential of hydrocarbon resources in this area. This paper determines the genetic types of oil and gas through geological and geochemical analyses. Combined with the geochemical characteristics of peripheral oil and gas reservoirs (Wucaiwan Oil Field, Kelameili Gas Field, and Dinan uplift), the oil and gas sources in the Dongdahaizi Depression are determined, and the oil and gas resources that have been hidden in the Dongdahaizi Depression are systematically studied.

2. GEOLOGICAL SETTING

The Dongdahaizi Depression is located in the Northeast of the Junggar Basin, between the Dishuiquan fault zone and the Dongdahaizi north fault zone. Its surface is covered by a desert (Figure 1). Previous studies have shown that the Dongdahaizi Depression has experienced several critical stages of tectonic movement, especially the long-term volcanic activity during the Carboniferous promoted the source rocks to reach a higher maturity stage. Frequent tectonic movements cause severe erosion of Triassic strata and restrict the development of Triassic source rocks in the work area. The Himalayan movement caused the Dongdahaizi Depression to tilt to the southwest, thus changing the high level in the southwest and the low level in the northeast to the structural pattern of the slope in the Northeast. There are three sets of thick argillaceous deposits in the Dongdahaizi Depression: the Carboniferous carbonaceous mudstone deposit, the Permian dark-gray mudstone deposit, and the Jurassic carbonaceous mudstone deposit (Figure 2).

3. SAMPLES AND METHODS

3.1. Sample Acquisition. For the present research, 64 samples were collected, including 30 source rocks from the Jurassic to the Permian (Tables 1 and 2), 21 natural gas samples from the DN7, DN8, and DN9 (Table 3), 11 crude oil samples from the Pingdiquan and Wutonggou Formations of the Lower Permian Series, and 2 crude oil samples from the Xishanyao Formation of the Middle Jurassic Series (Table 4). Organic matter type, maturity, and other indexes of these rock samples were tested. Saturated hydrocarbon mass spectrometry and chromatographic analysis used several rock samples and 13 crude oil samples. Twenty gas samples of the Jurassic and Permian were tested with natural gas composition and carbon isotope analysis.

Figure 1. Location map of the Northeast of the Dongdahaizi Depression, Junggar Basin.
hydrogen chloride before the experiment. Samples were dried at 50 °C for 24 h and analyzed with a carbon analyzer (LECO CS-230) for organic carbon content. The Rock-Eval 6 pyrolyzer was used for samples to determine the basic geochemical parameters of $S_1$, $S_2$, and $T_{max}$ according to Espitalié et al. In general, Leica MPV Compact No. 2 is a good tool for measuring the reflectivity of virosomes of organics, whose test uses an upgraded oil immersion lens and a Leica MPV Compact No. 2 reflective light microscope equipped with a microphotometer to test $R_0$. Considering the difference in optical properties of each vitrinite in the same sample, no less than 30 grains of vitrinite were counted during the vitrinite reflectance analysis. Optical microscopy analyses were carried out on grain pellets ground to 1 mm following ISO 7404-2:2009 for sample preparation, ISO 7404-5:2009 for vitrinite reflectance measurements, and ISO 7404-3:2009 for maceral analysis.

### 3.3. Saturated Hydrocarbon Chromatography, Mass Spectrometry

Subsamples were extracted with a mixture of dichloromethane/methanol (3:1, v/v) in a Soxtherm system (Gerhardt). The extracts were concentrated by rotary evaporation at 40 °C, filtered (0.45 μm), and finally dissolved in dichloromethane. Later, an aliquot of each rock extract was fractioned into saturated and aromatic hydrocarbons and polar compounds. According to the method, the asphaltene fraction was precipitated with $n$-heptane in a 1:40 v/v ratio. Then, saturates were separated from aromatic and resin fractions by liquid chromatography. The columns were filled with silica gel and alumina. The saturated hydrocarbons were eluted with hexane, and the aromatics, with a mixture of dichloromethane/hexane (4:1 v/v). The experiment conforms to an international standard. The Agilent 5975i mass spectrometer was used to measure saturated hydrocarbons in crude oil and reservoir extracts. Helium is used as a carrier gas and combined with

| System | Stratigraphy | tectonic movement | Lithology | Source rocks | Reservoir | Cap rocks | Sample points |
|--------|--------------|--------------------|-----------|--------------|-----------|-----------|---------------|
| Quaternary |                | Himalayan period | | | | | Sample points of source rocks |
| Neogene |                |                    | | | | | |
| Cretaceous | Upper Shishugou J.s | Yanshanian period | | | | | |
|          | Middle Xishanyao J.x | | | | | | |
|          | Lower Sangonghe J.s | | | | | | |
|          | Budaowan J.b | | | | | | |
| Jurassic | Upper and Middle Xiaoquan T.i,xq | Indonesian period | | | | | |
|          | Lower Jiucuiyi T.j | | | | | | |
| Triassic | Upper Wutonggo P.wt | | | | | | |
|          | Middle Pingdi-quan P.p | | | | | | |
|          | Jiangjun-miao P.j | | | | | | |
| Permian | Upper Batamayi-lieshan C.b | Hercynian period | | | | | |
|          | Dishui-quan C.d | | | | | | |
|          | Tamugang C.t | | | | | | |
| Carboniferous |                |                    | | | | | |
| Devonian |                |                    | | | | | |

Figure 2. Integrated geologic column of the Dongdaohaizi Depression, Junggar Basin.
Table 1. Geochemical Features of Source Rocks from the Dongdaohaizi Depression, Junggar Basin

| well  | lithology | depth (m) | formation | TOC (wt %) | S₁ + S₂ (mg/g) | chloroform bitumen “A” | HI | T_max (°C) | R_o (%) |
|-------|-----------|-----------|-----------|------------|----------------|-------------------------|----|------------|---------|
| Cc2   | mudstone  | 3732      | C₃,d      | 0.96       | 6.26           | 0.1115                  | 132.29 | 445        | 1.2     |
| C2    | mudstone  | 1706.1    | C₃,b      | 0.57       | 2.97           | 0.0096                  | 132.39 | 448        |         |
| C26-1 | dark-gray mudstone | 3124.2 | C₃,b | 0.46 | 2.83 | 0.008 | 129.05 | 431 | 1.3   |
| C26-2 | dark-gray mudstone | 3124.1 | C₃,b | 0.19 | 1.45 | 0.0062 | 118.65 | 452 | 1.3       |
| C26-3 | mudstone  | 3124.5    | C₃,b      | 0.45       | 6.05           | 0.0033                  | 100.9  | 448        | 1.49    |
| C26-4 | dark-gray mudstone | 3124.5 | C₃,b | 1.64 | 8.37 | 0.0063 | 109.52 | 453 | 1.46     |
| C26-5 | dark-gray mudstone | 3124.5 | C₃,b | 0.59 | 6.18 | 0.0135 | 116.5  | 452 | 1.45   |
| D12-1 | dark-gray mudstone | 1067.5 | C₃,d | 0.65 | 7.88 | 0.0425 | 40.8  | 437 | 1.25     |
| D12-2 | dark-gray mudstone | 1125.4 | C₃,d | 0.84 | 2.9  | 0.0749 | 52.6  | 445 | 0.96     |
| D403  | dark-gray mudstone | 3606.3 | C₃,d | 0.98 | 10.35 | 0.0526 | 74.9  | 438 | 1.31     |
| D7-1  | dark-gray mudstone | 2255.4 | P   | 0.94 | 5.4  | 0.0847 | 63.3  | 422 |         |
| D7-2  | dark-gray mudstone | 2378.1 | P   | 1.57 | 10.31 | 0.0041 | 75.4  | 427 |         |
| D7-3  | dark-gray mudstone | 2416.6 | P   | 1.36 | 6.77 | 0.0085 | 153   | 423 |         |
| D7-4  | dark-gray mudstone | 2510.4 | P   | 1.61 | 7.67 | 0.0006 | 85.4  | 445 |         |
| D7-5  | dark-gray mudstone | 2526.6 | P   | 2.52 | 26.18 | 0.0057 | 122.2 | 442 |         |
| D7-6  | dark-gray mudstone | 2586.7 | P   | 2.06 | 17.08 | 0.0463 | 154.3 | 438 |         |
| D7-7  | dark-gray mudstone | 2688.1 | P   | 4.09 | 29.72 | 0.0532 | 95.5  | 446 |         |
| D7-8  | dark-gray mudstone | 2498.9 | P   | 3.2  | 15.48 | 0.0046 | 210.9 | 445 |         |
| D7-9  | dark-gray mudstone | 2642.5 | P   | 2.37 | 12.7 | 0.0097 | 169.1 | 449 |         |
| D7-10 | dark-gray mudstone | 2500.4 | P   | 4.03 | 26.37 | 0.0089 | 140.9 | 448 |         |
| DN9   | dark-gray mudstone | 6022.2 | P₃,wt | 0.43 | 2.69 | 0.0967 | 166   | 447 | 0.59     |
| DN9   | dark-gray mudstone | 3090.7 | P₃,p   | 1.49 | 6.97 | 0.1313 | 139   | 446 | 0.69     |
| DN9   | dark-gray mudstone | 3550.2 | P₃,p   | 1.98 | 11.3 | 0.1122 | 156   | 453 | 0.76     |
| DN9   | dark-gray mudstone | 4103.4 | P₃,wt | 0.96 | 3.26 | 0.1289 | 89.3  | 449 | 0.86     |
| D9-1  | coal      | 492.4     | J₁,x     | 64.62 | 23.73 | 0.0096 | 52.4  | 439 | 0.48     |
| D9-2  | coal      | 504.5     | J₁,x     | 42.15 | 27.48 | 0.0489 | 165   | 433 | 0.5      |
| D9-3  | coal      | 520.8     | J₁,x     | 44.48 | 21.88 | 0.0275 | 139   | 438 | 0.51     |
| DX14  | dark-gray mudstone | 2984.5 | J₁,b   | 1.14 | 5.56 | 0.0321 | 67.6  | 436 | 0.65     |
| DX13  | dark-gray mudstone | 2657.2 | J₁,t   | 2.01 | 9.29 | 0.0494 | 96    | 439 | 0.48     |
| DN9   | dark-gray mudstone | 1888.5   | J₃,x    | 1.56 | 7.36 | 0.3094 | 124   | 426 | 0.97     |

Note: TOC, total organic carbon, %; S₁ + S₂, potential hydrocarbon generation amount, mgHC/grock; chloroform bitumen “A”, dissolvable organic matter in rocks, expressed as a percentage of rock mass, %; R_o, vitrinite reflectance (%); T_max, temperature with the maximum hydrocarbon generation (°C); HI, hydrogen index (mg/g).

Table 2. Physical Properties of Crude Oils from Different Structures in the Northeast of the Dongdaohaizi Depression, Junggar Basin

| well | strata  | depth(m) | density (g/cm³) | freezing point (°C) | wax content (%) | fractionation point (°C) | oil production (t/d) | gas production (x10⁴ m³/d) |
|------|---------|----------|----------------|---------------------|----------------|-------------------------|----------------------|--------------------------|
| D12  | J₁,b    | 1036.5–1041.5 | 0.87 | 7.67 | 12 | 8.86 |
| D2   | J₁,b    | 991–1000       | 0.90 | 5.56 | −10 | 1.46 |
| D20  | J₁,b    | 1388–1396      | 0.88 | 1.5 | −22 | 15.32 | 0.0298 |
| D310 | J₁,b    | 981            | 0.91 |         |         | 18.1 |
| DN1  | P₁,wp   | 2760.5        | 0.85 | 11.02 | 22.5 | 127 | 0.42 |
| DN1  | P₁,wp   | 2760.5        | 0.86 | 9.57 | 18 | 106 | 0.42 |
| DN1  | P₁,wp   | 2760.5        | 0.85 | 8.76 | 13 | 90 | 0.42 |
| DN8  | P₁,wp   | 3956–3972      | 0.8169 | 7.07 | 25.37 | 105 | 0.261 |
| DN9  | P₁,wp   | 3842–3868      | 0.86 | 7.36 | 12 | 0.65 |
| DN10 | J₃,x    | 1888–1892      | 0.765 | 1.04 | −40.5 | 1.92 | 1.666 |

HP6890 gas chromatography equipped with an H-5MS chromatography column (60m × 0.25 mm²) with 0.25 μm coating. The mass spectrometer operates in the full-scan mode, with quantification based on the peak area response in a specific chromatogram. The experimental test was completed by the State Key Laboratory of the School of Earth Science and Technology, Southwest Petroleum University.

3.4. Molecular Composition and Carbon Isotope Analysis of Natural Gas. The gas samples were divided into three parts for analysis. The stable carbon isotope values of natural gas were measured based on the thermal science Delta V mass spectrometry interface method and trace gas chromatograph (GC)-ULTRA gas chromatography. First, hydrocarbon gas components and carbon dioxide were separated by a fused silica capillary column (60 × 0.25 mm² i.d.) on GC. They were then injected into a mass spectrometer for quantitative analysis after the hydrocarbon gas components had transformed into carbon dioxide at the combustion interface. The temperature of the GC oven was raised from 35 to 85 °C at the rate of 10 °C min⁻¹ and then to 255 °C at the rate of 5 °C min⁻¹ for 8 min. The more stable helium is used as the carrier gas. Based on the international standard of carbon isotope ratio measurement,
two-point calibration was carried out on the experimental data, and the repeat analysis accuracy of each hydrocarbon gas compound in the VPDB standard was ±0.5‰. According to the VPDB standard, the stable carbon isotopic values are expressed in the δ notation per mil (‰).

4. RESULTS

4.1. Characteristics of Source Rocks. 4.1.1. Evolution of Source Rocks. The abundance, type, maturity, and distribution of organic matter in source rocks determine the potential of hydrocarbon resources in oil-bearing basins. Three hydrocarbon source rocks were evaluated: Carboniferous mudstone-Carbonaceous mudstone, Permian Dishuiquan Formation dark mudstone, and Jurassic coal-mudstone-carbonaceous mudstone (Table 1). More than 70% of the samples had TOC greater than 1.0% and S1 + S2 greater than 6.0 mg/g, and the organic matter abundance index shows that Permian and Jurassic source rocks have also reached the standard of good to excellent source rocks (Figure 3). The rock hydrogen index (HI) and pyrolysis T_max curve can classify the types of organic matter, and Figure 4 shows that the selected samples were almost all projected onto the pattern areas of type II–III. Kerogen is mainly type II and contains a small amount of type III, indicating the aquatic plankton source.

The kerogen vitrinite reflectance (R_o) and the temperature of the maximum pyrolysis yield (T_max) of source rocks can determine the evolution degree of source rocks. The evolution degree of source rocks is different in different strata in the study area. The evolution degree of Carboniferous source rocks is relatively high. Vitrinite reflectance of Carboniferous source rocks is 0.96–1.49%, with an average value of 1.29%, reaching a high maturity stage. The maturity of Permian and Jurassic source rocks is relatively low, and the main body is distributed within the range of less than 0.8%, which belongs to the product of the low maturity stage (Table 1); it is related to the fact that the selected samples come from high structural parts.

According to stratigraphic division, sedimentary denudation thickness, the geothermal gradient of different times, and the measured R_o (%) profile value of the work area, one-dimensional numerical simulation results are obtained, and the thermal evolution history of burial and organic matter of a single-well stratum is reconstructed. Based on the seismic interpretation results, the evolution characteristics of hydrocarbon source rocks at different positions in the Depression were analyzed. A total of eight position points were selected: Sample A (X: 5001 531.0, Y: 15 516 631.2), Sample B (X: 4971 485.6, Y: 15 516 710.3), Sample C (X: 4995 018.2, Y: 15 541 394.9), Sample D (X: 4967 068.3, Y: 15 542 074.3), Sample E (X: 4978 291.9, Y: 15 559 009.2). Table 3. Compositions and Carbon Isotopic Compositions of the Northeast Natural Gas in the Dongdaohaizi Depression

| well | strata | depth(m) | N_2 | CO_2 | CH_4 | C_2H_6 | C_3H_8 | n-C_3 | i-C_3 | n-C_4 | i-C_4 | CH_3 | C_4H_8 | C_5H_10 | δ(13C) (%) |
|------|--------|----------|-----|------|------|--------|--------|-------|-------|-------|-------|------|--------|--------|------------|
| DN8  | P_xt   | 3856.00–3972.00 | 4.63 | 0.03 | 57.72 | 11.60 | 9.48 | 2.47 | 4.58 | 1.22 | 2.19 | −31.14 | −29.54 | −28.45 | −27.83 |
| DN8  | P_xt   | 3956.00–3972.00 | 6.04 | 0.05 | 64.63 | 11.80 | 8.90 | 2.32 | 3.81 | 0.96 | 1.10 | −31.02 | −29.03 | −28.39 | −27.67 |
| DN8  | P_xt   | 3956.00–3972.00 | 11.7 | 0.06 | 73.45 | 7.49 | 7.49 | 2.51 | 1.90 | 0.24 | 0.74 | −31.15 | −29.98 | −28.21 |
| DN8  | P_xt   | 3956.00–3972.00 | 9.46 | 0.04 | 75.02 | 8.19 | 4.11 | 0.84 | 1.29 | 0.30 | 0.38 | −31.25 | −29.48 | −28.59 | −28.03 |
| DN8  | P_xt   | 3956.00–3972.00 | 6.18 | 0.03 | 75.49 | 9.78 | 4.95 | 0.99 | 1.48 | 0.33 | 0.40 | −30.01 | −29.69 | −28.18 |
| DN8  | P_xt   | 3956.00–3972.00 | 3.38 | 0.05 | 68.70 | 13.98 | 8.14 | 1.66 | 2.51 | 0.52 | 0.62 | −30.89 | −29.58 | −28.73 | −27.83 |
| DN9  | J_xt   | 1888.00–1892.00 | 6.86 | 0.07 | 68.79 | 3.33 | 1.27 | 0.33 | 0.39 | 0.13 | 0.11 | −29.17 | −27.09 | −24.56 |
| DN9  | J_xt   | 1888.00–1892.00 | 7.47 | 0.16 | 66.00 | 3.49 | 1.39 | 0.37 | 0.46 | 0.15 | 0.14 | −29.09 | −26.89 | −24.36 |
| DN9  | J_xt   | 1888.00–1892.00 | 7.29 | 0.15 | 66.67 | 3.40 | 1.33 | 0.35 | 0.40 | 0.12 | 0.10 | −29.29 | −26.97 | −24.03 |
| DN9  | J_xt   | 1888.00–1892.00 | 7.63 | 0.19 | 85.92 | 3.47 | 1.36 | 0.40 | 0.45 | 0.17 | 0.15 | −29.26 | −27.26 | −24.79 |
| DN9  | J_xt   | 1888.00–1892.00 | 7.77 | 0.18 | 86.17 | 3.40 | 1.31 | 0.35 | 0.40 | 0.13 | 0.11 | −29.36 | −27.87 | −24.22 |
| DN9  | J_xt   | 1888.00–1892.00 | 7.60 | 0.17 | 86.28 | 3.43 | 1.33 | 0.35 | 0.41 | 0.13 | 0.11 | −29.30 | −27.36 | −25.01 |
| DN7  | P_xt   | 3006.00–3325.00 | 2.00 | 0.12 | 87.60 | 7.16 | 2.17 | 0.35 | 0.37 | 0.07 | 0.07 | −28.34 | −27.19 | −25.82 | −24.09 |
| D103 | C      | 3050.00–3062.00 | 2.98 |       | 84.79 | 5.43 | 2.54 | 1.08 | 0.88 | 0.48 | 0.27 | −29.93 | −29.61 | −25.00 | −25.07 |
| D403 | C      | 3594.00–3606.00 | 3.28 | 0.05 | 88.72 | 4.70 | 1.64 | 0.53 | 0.49 | 0.18 | 0.14 | −29.78 | −27.51 | −24.85 | −25.12 |
| DX183| C      | 3625.00–3640.00 | 1.94 |       | 89.12 | 5.31 | 2.04 | 0.58 | 0.55 | 0.17 | 0.12 | −30.41 | −26.83 | −23.59 |
| DX33 | C      | 3518.00–3526.00 | 4.31 | 0.08 | 88.27 | 3.75 | 1.89 | 0.48 | 0.59 | 0.20 | 0.16 | −29.40 | −27.48 | −26.83 | −24.44 |
| DX10 | C      | 3070–3084   |       |       |        |       |       |       |       |       |        | −30.06 | −27.73 | −24.47 |
| DX5  | C      | 3650–3665   |       |       |        |       |       |       |       |       |        | −29.71 | −26.84 | −25.34 | −25.23 |
| DX21 | C      | 2848.74–2970.00 |     |       |        |       |       |       |       |       |        | −29.37 | −27.05 | −24.99 | −24.36 |

From the Pr/Ph ratio of basking shark alkane to phytane (Pr/Ph) is considered an essential indicator of the redox environment at deposition, and some scholars have suggested that it also influences the type and maturity of organic matter. From the Pr/Ph distribution characteristics of three sets of hydrocarbon source...
rock extracts in the Dongdaohaizi Depression (Figure 7), it can be seen that the Pr/Ph values of hydrocarbon source rock products in Carboniferous and Permian strata are relatively close, generally less than 3.0, while those in the Jurassic strata are generally greater than 3.0, which is quite different from the above aspects, with good discrimination between the two. It is different from the extracts of Permian and Carboniferous source rocks. This also reflects that the sedimentary environment of the Dongdaohaizi Depression significantly changed from Paleozoic to Mesozoic.

The relative contents of $C_{27}$, $C_{28}$, and $C_{29}$ steranes depend to a large extent on the material input of source rocks, which is a commonly used biogenic index. The distribution of sterane content in the study area’s three sets of source rock products is also obviously different. Sterane content distribution of hydrocarbon source rock extracts of the Permian Pingdiquan Formation is dominated by sterane $C_{28}$ and sterane $C_{29}$, with the highest content being of sterane $C_{29}$ followed by sterane $C_{28}$, accounting for more than 80% of the total sterane content. Sterane $C_{27}$ sterane also has a relatively high abundance, similar to that of $C_{28}$ and $C_{29}$. This also affects the sedimentary environment of the Dongdaohaizi Depression significantly changed from Paleozoic to Mesozoic.

Table 4. Summary of Biomarker Parameters of Crude Oil Samples in the Dongdaohaizi Depression

| well | strata | depth(m) | $Pr/Ph$ | $Pr/nC_{17}$ | $Ph/nC_{18}$ | $Pr + nC_{17}^{(17)}$ | $Ph + nC_{18}^{(18)}$ | $Ts/Tm$ | $T/(T + P)$ | $γ/C_{31}$H | $C_{22}$S/(S + R) | $C_{21}$/C_{23} | $C_{27}$-sterane | $C_{28}$-sterane | $C_{29}$-sterane |
|------|--------|---------|--------|-------------|-------------|-----------------|-----------------|--------|-----------|-------------|---------------|---------------|---------------|---------------|---------------|
| DN1  | P, P   | 2723.00| 2724.00| 1.60      | 0.44        | 0.27            | 0.490           | 0.48   | 0.42      | 0.57         | 1.42           | 0.29          | 0.53          | 0.48          | 0.57          |
| DN1  | P, P   | 2766.00| 2768.00| 1.20      | 0.69        | 0.07            | 0.814           | 0.29   | 0.25      | 0.34         | 0.60          | 1.31          | 0.20          | 0.34          | 0.46          |
| DN1  | P, P   | 2810.00| 2811.00| 1.10      | 0.7            | 0.38           | 0.610           | 0.28   | 0.031     | 0.26         | 0.57          | 1.42          | 0.18          | 0.31          | 0.50          |
| DN1  | P, P   | 2880.00| 2881.00| 1.20      | 0.45        | 0.36            | 0.495           | 0.24   | 0.26      | 0.16         | 0.61          | 1.06          | 0.28          | 0.18          | 0.54          |
| DN1  | P, P   | 3225.00| 3227.00| 1.60      | 0.22        | 0.13            | 0.227           | 0.37   | 0.26      | 0.42         | 0.58          | 1.31          | 0.15          | 0.28          | 0.57          |
| DN1  | P, P   | 3842.00| 3868.00| 1.90      | 0.56        | 0.32            | 0.726           | 2.05   | 0.40      | 0.55         | 0.46          | 0.95          | 0.17          | 0.24          | 0.59          |
| DN1  | P, P   | 3710.00| 3778.00| 1.76      | 0.49        | 0.32            | 0.636           | 2.68   | 0.33      | 0.43         | 0.41          | 1.02          | 0.14          | 0.27          | 0.60          |
| DN7  | P, wt  | 3306.00| 3325.00| 1.78      | 0.43        | 0.25            | 0.509           | 0.58   | 0.21      | 0.17         | 0.56          | 0.92          | 0.20          | 0.27          | 0.65          |
| DN7  | P, wt  | 3959.43| 3961.94| 1.83      | 0.49        | 0.31            | 0.642           | 2.87   | 0.79      | 0.37         | 0.24          | 0.96          | 0.19          | 0.24          | 0.57          |
| DN7  | P, wt  | 3970.94|        | 1.83      | 0.49        | 0.31            | 0.642           | 2.39   | 0.80      | 0.34         | 0.26          | 1.00          | 0.17          | 0.24          | 0.59          |
| DN9  | J, x   | 1888.00| 1982.00| 2.31      | 0.57        | 0.31            | 0.858           | 0.55   | 0.31      | 0.28         | 0.51          | 1.06          | 0.14          | 0.23          | 0.63          |
| DN9  | J, x   | 1888.00| 1982.00| 2.15      | 0.58        | 0.31            | 0.843           | 0.60   | 0.36      | 0.18         | 0.49          | 0.98          | 0.11          | 0.25          | 0.65          |

$Pr$, pristane; $Ph$, phytane; $Ts/Tm$, 18$\alpha$(H)-22,29,30-trisnorhopane/17$\alpha$(H)-22,29,30-trisnorhopane; $T/(T + P)$, tricyclic/(tricyclic + pentacyclic) terpane; $γ/C_{31}$H, gammacerane/C_{31} hopanes; $C_{22}$S/(S + R), C_{22} homohopane 22S/C_{22} homohopane (22S + 22R); $C_{21}$/C_{23}, C_{21} tricyclic terpane/C_{23} tricyclic terpane; $C_{27}$-steranes, $C_{27}$ steranes ($α$20R); $C_{28}$-steranes, $C_{28}$ steranes ($α$20R); $C_{29}$-steranes, $C_{29}$ steranes ($α$20R).
The distribution characteristics of steranes extracted from Jurassic hydrocarbon source rocks are different from those from Permian and Carboniferous ones. The C_{29} sterane content is the highest, C_{27} and C_{28} sterane contents are relatively low, and the C_{29} sterane content is generally above 60%. (Figure 8). By projecting the relative composition data of steranes from three sets of hydrocarbon source rock extracts into the trigonometry chart (Figure 9), it can be found that the distribution of steranes has a good degree of discrimination; thus, a chart can be established to judge the oil and gas sources in the research area.

The carbon isotope characteristics of the source rock products of the three sets of strata show specific differences. The Permian source rock products’ carbon isotopes had δ^{13}C values ranging between −28 and −34.5‰, generally less than −30‰, showing the characteristics of a partial sapropelic organic source. However, the carbon isotope (δ^{13}C) distribution range of the products of Carboniferous and Jurassic source rocks is relatively similar, with the δ^{13}C value ranging from −24 to −30‰, and the...
main body having values greater than $-28\%$, which is different from the products of Permian source rocks and shows the characteristics of the partial humic organic source.

### 4.2. Oil and Gas Characteristics

The physical properties of crude oil samples from several wells in the Dongdahaizi Depression were analyzed (Table 2). The Permian Pingdiquan Formation and the Wutonggou Formation are the main source rock zones in the study area, showing excellent oil and gas displays. The eastern section of the Dinan uplift adjacent to the study area is mainly composed of crude oil reservoirs, and the crude oil density value at the high structural part is generally greater than 0.8169 g/cm$^3$ and the freezing value, indicating that its origin may be different from that of the crude oil in the Dinan fault block and the eastern part of the Dinan bulge. In addition, the average density value of Jurassic Xishanyao Formation crude oil in well DN9 is 0.762 g/cm$^3$, and the average freezing value is $-40.5^\circ\text{C}$, which is lower than that of Permian crude oil, indicating that its source and origin are different from the other wells in this area.

#### 4.2.1. Natural Gas Geochemical Characteristics

The natural gas in the study area mainly comes from Carboniferous and Permian source rocks. The carbon isotope value of natural gas from the Carboniferous system is relatively heavy, with a methane carbon isotope value ($\delta^{13}\text{C}_{\text{CH}_4}$) between $-29$ and $-31\%$, the ethane carbon isotope value ($\delta^{13}\text{C}_{\text{C}_2\text{H}_6}$) higher than $-25\%$, the propane carbon isotope value ($\delta^{13}\text{C}_{\text{C}_3\text{H}_8}$) higher than $25\%$, and the difference between ethane carbon isotope and methane carbon isotope between 4 and $12\%$. The carbon isotope of natural gas from the Pingdiquan Formation of the Permian (P$_2$p) is relatively light, with the methane carbon isotope value ($\delta^{13}\text{C}_{\text{CH}_4}$) ranging from $-45$ to $-30\%$, the ethane carbon isotope value ($\delta^{13}\text{C}_{\text{C}_2\text{H}_6}$) being lower than $-29\%$, and the propane carbon isotope value ($\delta^{13}\text{C}_{\text{C}_3\text{H}_8}$) being lower than $-25\%$. Therefore, the types of gas, the carbon isotope of natural gas, can be used to distinguish sources to carry out gas source comparison. $^{17-40}$

#### 4.2.1.1. Molecular Composition of Natural Gas

Gas was produced in the wells DN8 and DN9 in the Dongdahaizi Depression, but the natural gas characteristics differed (Table 3). The methane content in the DN8 well was 57.722$-75.49\%$ (mean 69.17%), the ethane content was 7.49$-12\%$, and the propane content was 13.98$-22.5\%$ (mean 15.68%). Moreover, the heavy hydrocarbon content was large, belonging to typical moisture. $^{15,41-43}$ The dried coefficient of natural gas in well DN9 is relatively large, with the methane content ranging from 85.92 to 86.79$\%$ (average of 86.31$\%$) and the ethane content ranging from 3.35 to 3.42$\%$ (average of 3.42$\%$). In non-hydrocarbon gases, the content of both nitrogen and argon is relatively high, ranging from 3.38 to 11.75$\%$, with an average of 6.8$\%$.

#### 4.2.1.2. Carbon Isotope Characteristics of Natural Gas

Carbon isotopes of natural gas are commonly used geochemical indicators. $^{16,17}$ The stable carbon isotope characteristics of natural gas in wells DN8 and DN9 are different. The carbon isotopes of Permian natural gas in the DN8 well have the characteristics of centralized distribution; the range was $-31.25$ to $-31.02\%$, with an average of $-30.72\%$. The carbon isotope value of $\delta^{13}\text{C}_{\text{CH}_4}$ mainly ranges from $-29.98$ to $-29.03\%$, and the average value is $-29.59\%$. The carbon isotope values of $\delta^{13}\text{C}_{\text{C}_2\text{H}_6}$ range from $-28.59$ to $-28.18\%$. The fractionation effect of $\delta^{13}\text{C}_{\text{CH}_4}$ and $\delta^{13}\text{C}_{\text{C}_2\text{H}_6}$ carbon isotopes is not apparent. The minimum difference between $\delta^{13}\text{C}_{\text{CH}_4}$ and $\delta^{13}\text{C}_{\text{C}_2\text{H}_6}$ in natural gas is only 0.32, with an average of 1.36, which is considered natural gas mixing. The value of $\delta^{13}\text{C}_{\text{C}_3\text{H}_8}$ of Jurassic natural gas in well area DN9 ranges from $-29.36$ to $-29.09\%$, with an average value of $-29.29\%$. The carbon isotope distribution of $\delta^{13}\text{C}_{\text{C}_3\text{H}_8}$ ranges from $-27.87$ to $-26.89\%$, with an average value of $-27.27\%$. The carbon isotope characteristics of natural gas are similar to those of Kelameili Gas Field’s and belong to the humic organic matter produced from the carboniferous system (Table 3). The carbon isotope values of...
well DN8 gas samples are less than $-28.5\%$‰, which is the origin of sapropelic natural gas.

Under normal circumstances, the carbon isotope values of methane $\delta^{13}C_{1}$ and ethane $\delta^{13}C_{2}$ maintain a fractionation gap of at least $5\%$‰; the natural gas from well DN8 (P$_3$ wt) has similar characteristics to that from typical Permian sources. It is worth noting that the methane–ethane fractionation value of natural gas in well DN8 is only 0.32. It was believed that there is a set of Carboniferous source rocks under the Permian sapropelic source rocks to supply natural gas to the upper layer. The humic source gas is heavier than the sapropelic source gas in the carbon isotope. The methane carbon isotope will become heavier if the
Carboniferous source gas is mixed. The $C_2/C_3$ index in the hydrocarbon gas is less affected by the source rock type and can mainly reflect the maturity of hydrocarbons. $^{37,39,42}$ $C_i/C_3$ values of natural gas samples of wells DN8 and DN9 are less than 2.0, and more than half of the gas samples have $C_2/iC_4$ values less than 10, and the hydrocarbon gas components contain higher butane and pentane contents. Hexane, heptane, and octane are measured in some samples, and the heavy hydrocarbon content is generally between 4.67% and 63.29%, which indicates that pyrolysing gas formed by hydrocarbon-generating parent materials in the mature-highly mature stage exists in the research area. At the same time, the high content of $N_2$ indicates that the hydrocarbon-generating parent material of the natural gas is in a mature-highly mature stage.

4.2.2. Crude Oil Characteristics. 4.2.2.1. Carbon Isotope and Maturity Parameters of Crude Oil. The carbon isotope values of the crude oil samples (P$_{1w}$, P$_{2}$, P$_{3}$, and J$_{3x}$) are generally small, among which the carbon isotope ($\delta^{13}C$) value of the crude oil of well DN8 (P$_{1w}$) is $-29.88\%e$, the carbon isotope values of well DN10 (P$_{2}$) crude oil samples are relatively small, with the $\delta^{13}C$ values ranging from $-30.04\%e$ to $-30.94\%e$, and the $\delta^{13}C$ value of well DN9 (J$_{3x}$) crude oil samples is about $-28.77\%e$, which is lower than the typical Permian Pingdingqian Formation source rock in the eastern part of the Dinan bulge but significantly higher than the typical carboniferous source rock product (its values are generally greater than $-25\%e$).

Isomerization parameters values $C_{2920S}(S + R)$ of sterane from crude oil samples (P$_{3w}$, P$_{2}$, and J$_{3x}$) are almost uniformly distributed in the range of 0.4–0.5, and $C_{2920S}(\beta\beta + \alpha\alpha)$ values are also concentrated in the range of 0.5–0.6. There is no apparent difference, reaching equilibrium and no “inversion,” indicating that the main body of crude oil should be the product from the maturity stage of the source rock (Figure 10).

The application range of the Hopane maturity parameter $T_i/(T_i + T_m)$ is extensive. The $T_i/(T_i + T_m)$ index can reflect the maturity of crude oil to a certain extent, which previous studies in neighboring areas have also confirmed. The crude oil samples’ $T_i/(T_i + T_m)$ values from the Dongdaohaizi Depression show specific differences. The $T_i/(T_i + T_m)$ values of well DN8 (P$_{1w}$) located in the slope area of the Depression are more significant than 0.7, significantly higher than the other areas’ crude oil samples (DN9 well, DN10 well, DN1 well, and DN7 well), while the $T_i/(T_i + T_m)$ values of the other areas’ crude oil samples are rarely greater than 0.6. This maturity characteristic is also shown in the $T_i/(T_i + P)$ value (Table 4). The $T_i/(T_i + P)$ value of well DN8 (P$_{1w}$) is more significant than 0.8, while the maturity parameter $T_i/(T_i + P)$ value of the DN1 well crude oil sample is only 0.21. The parameter $(Pr + nC17)/(Ph + nC18)$ is less affected by maturity; $^{26,27}$ for example, it is 0.23–0.72 for heavy oils (including P$_{3p}$ and P$_{1w}$ crude oils known to have low maturity), and the parameter value of light oil of the DN9 well with a low density is 0.86 (Table 2). This is consistent with other indicators. These data provide additional evidence that crude oils within a group are derived from the same source material and depositional environment.

4.2.2.2. Geochemical Characteristics of Crude Oil. The saturated hydrocarbon chromatograms of crude oil samples of wells DN7 (P$_{3w}$), DN8 (P$_{2}$), and DN9 (J$_{3x}$) are relatively well preserved, while the oil reservoirs in the eastern section of the Dinan uplift area (wells D2, D20, LN1) are relatively poorly preserved, which is related to their high structure and relatively shallow oil depth. Crude oil n-alkanes from the well DX9 located in the middle of the Dinan uplift and the well DN8 located in the slope area are well preserved in reservoir rock samples. The saturated hydrocarbon chromatogram shows that the carbon number of the samples has a high content between C$_{15}$ and C$_{31}$. The secondary changes of the reservoir are relatively weak, especially the light hydrocarbon content is relatively high, which are mainly affected by two factors. The first is that crude oil is produced from hydrocarbon source rocks with a higher evolution degree, and crude oil contains more short-chain hydrocarbons. Second, it is located in the slope area of the Depression, with a deeper burial and relatively better preservation of light components. Crude oil as a whole has not suffered noticeable secondary changes. In addition, the Pristane and Phytane of the reservoir rock samples from the Dongdaohaizi Depression are entirely preserved, and the Pr/Ph value of crude oil from the Dongdaohaizi Depression is less than 3.0, which indicates a sedimentary environment of weak oxidation and weak reduction. The Pr/Ph values of wells DN1, DN7, DN8, and DN10 crude oil samples range from 1.2 to 1.92, with an average of 1.627. DN9 is relatively higher, and its crude oil sample Pr/Ph values range from 2.15 to 2.31, with an average value of 2.0 (Figure 11). Based on the Pr/Ph analysis alone, the crude oil in the slope area of the Donghaizi Depression conforms to the characteristics of Permian or Carboniferous source rock products and should not belong to the Jurassic source.

The content of tricyclic terpenes of well DN9 crude oil samples (J$_{3x}$) is greater than that of hopanes, with a ratio of 1.24–1.28. The content of tricyclic terpenes of well DN8 crude oil samples is larger than the Khotan series, with a ratio of 3.87–

![Figure 10. Cross-plot of biomarkers of crude oil in the Northeast of the Dongdaohaizi Depression.](https://doi.org/10.1021/acsomega.2c00725)
4.07. The $T_s/T_m$ values of wells DN10 and DN9 crude oil samples are less than 1.0; the $T_s/T_m$ values of well DN8 crude oil samples are 2.87−3.83 and contain certain gamma paraffins. The original gamma paraffin value of well DN9 is lower than that of wells DN8 and DN9. According to the distribution characteristics of regular steranes in the samples, the abundance of C$_{29}$ regular steranes in well DN9 (J$_{2x}$) and well DN10 (P$_{3wt}$) is relatively higher than that in well DN8 (P$_{3wt}$). The contents of C$_{21}$-pregnane and C$_{22}$-litter pregnane with a low carbon number is relatively low in well DN7, with the highest content in well DN8 (P$_{3wt}$) and the mid-range content in well DN9 (J$_{2x}$), indicating that there may be some differences in the sources of crude oil (Figure 12).

5. DISCUSSION

5.1. Influence of Thermal Evolution on Geochemical Parameters. Some geochemical parameters with critical environmental indicators, such as Pr/Ph, C$_{29}$20S(S + R), C$_{29}$ββ(ββ + αα), and so on, were affected to some extent by the degree of thermal evolution. Therefore, using $R_o\%$ and $T_s/T_m$ as maturity indicators, the influence of related geochemical parameters is discussed. The TOC and S$_1 + S_2$ indices of organic matter abundance do not change regularly with the increase of maturity (Figure 13a), while TOC and S$_1 + S_2$ show a good positive correlation (Figure 3). This is due to differences like the sample itself. Pr/Ph is an essential indicator of the paleoenvironment in this paper. The characteristics of Pr/Ph increasing in the low maturity stage, decreasing in the maturity stage, and then gradually becoming stable may be of universal significance in Meso-Cenozoic continental source rocks in China (Figure 13b).
With the increase in maturity, the $C_{29}\beta\beta / (\beta\beta + \alpha\alpha)$ ratio increases from 0.37 to 0.59 (Figure 13c), explaining that the $\beta$ configuration is more stable than the $\alpha$ configuration, which is consistent with previous conclusions. $C_{29}20S(S + R)$ remains unchanged in the evolution process (Figure 13d). The above geochemical parameters show little difference even in different thermal evolution stages and are applicable.

5.2. Origin and Source of Crude Oil. Carbon isotopic characteristics can be a good indicator of oil and gas sources. Generally, with the intensity of thermal evolution, the carbon
isotope gradually becomes heavier, but generally less than 2‰. On comparing the $\delta^{13}C$ values of the source rock with those of the crude oil samples, it can be seen that the carbon isotope and $\delta^{13}C$ values of crude oil samples are relatively light, which are similar to those of Permian source rocks (Figure 14). Therefore, Jurassic and Permian crude oil come from Permian source rocks. The $\delta^{13}C$ value of crude oil samples from the well DN9 reservoir is between Jurassic and Permian source rocks, but it is more similar to the carbon isotope characteristics of Permian source rocks. Therefore, the solid bitumen in the reservoir is mainly from Permian source rocks, a mixture of hydrocarbons produced by some of the Jurassic source rocks.

The composition of the relative content of sterane shows that the main body of crude oil samples is distributed within the characteristic range of Permian Pingdiquan Formation source rock products (Figure 15), which is relatively consistent with the previous analysis results. However, there are apparent zones between these samples and crude oil samples located in the Dinan fault block and the Dinan uplift, and its $C_{27}$ sterane relative content is lower, which is more consistent with the characteristics of Permian Pingdiquan Formation source rock products. However, some crude oil samples on the Dinan uplift (including the Dinan fault block) were distributed in the crossing range between Permian and Carboniferous source rocks. It can be seen from the comparative composition data of steranes that the crude oil on the well DN9 is not a pure Permian source, and there should be a small amount of mixed crude oil from other sources. The mixed crude oil is more likely to be the Carboniferous source.

DN8, DN9, and DN10 are located in the Northeast of the Dongdaohaizi Sag; they had different hydrocarbon characteristics, mainly constrained by the fault zone. The three wells are distributed along the Northeast in line; well DN10 is adjacent to well DN8 (Figure 16a), which is separated from well DN9 by the Dishuiquan fault during the middle Carboniferous to late Permian (Figure 16b). Theoretically, mature hydrocarbons at deep sites and germinal centers should migrate to here. Confined to the barrier of the Dishuiquan fault, Permian-

Figure 14. Carbon isotope distributions of the oil in the Northeastern Dongdaohaizi Depression.

Figure 15. Cross-plot of the regular sterane relative composition of the oil from the Dongdaohaizi Depression.
derived hydrocarbons migrated only to dripping DN8 and dripping DN10 well zones (Figure 16c). Well DN7, which has the same characteristics as hydrocarbons from the dripping well DN9 area, verifies that hydrocarbons from this block are from other sources.

5.3. Hydrocarbon Migration and Evolution. The evolution of hydrocarbon sources and the migration of oil and gas are significantly affected by tectonic movements. At the end of the Jurassic, the deep Permian source rocks of the Dongdaohaizi Depression had reached the stage of higher maturity, the Pingdiquan Formation source rocks of the well DN8 area had reached the stage of maturity, and the peak of crude oil generation began in the Early Cretaceous (Figure 17). During the late Cretaceous, the structural uplift adjusted, and the crude oil and associated gas in the high evolution stage of the Permian Pingdiquan Formation in the deep part of the Depression migrated to the slope area along with the bedding and migrated upward along the deep fault in the well DN8 area; finally, a reservoir was formed in the high part of the northeast structure. Fluid inclusions are diagenetic, and metallogenic fluids (fluids containing gaseous and liquid silicate melt) are wrapped in the mineral crystal growth process wrapped in crystal lattice defects or cavities of minerals; it is still in the main source of minerals to date. The sealed part has an obvious phase boundary with the main mineral. Fluid inclusions represent the geologic fluids retained during the formation of oil and gas in geologic time; filling and evolution history, the accumulation period, and time have important research significance.

Hydrocarbon inclusions in the Permian Wutonggou Formation of well DN8 are mainly distributed in groups, with quartz particles as the primary host. The homogenization temperature of inclusions is between 90 and 120 °C, mainly between 110 and 120 °C. The main oil and gas filling period is the end of the Early Cretaceous. After that, the tectonic movement caused the lower migration channel to open, and the Carboniferous natural gas migrated along the fault into the Permian Wutonggou Formation reservoir and mixed with the previous Permian natural gas (Figure 18). This process was accompanied by the mixing of crude oil and migration toward the slope. We have thus established the dynamic relationships between the crude oil of the northwestern Junggar Basin region and the hydrocarbon evolution history in the region. The findings of this study could be significant for guiding further exploration and development of crude oil as resources in the Permian system of the northwest Junggar Basin.

Figure 16. (a) Seismic and geological interpretation section of well DN8; (b) seismic and geological interpretation section of well DN9; and (c) seismic and geological interpretation section of well DN10.
1. The evolution and maturity of Permian Pingdiquan Formation source rocks gradually increased from the periphery to the center of the Depression, and the deep part of the Depression reached a mature stage. The Permian source rocks in the deep part of the slope of the Dongdaohaizi Depression have a high abundance, and suitable types of organic matter have reached a high-overmature stage and excellent hydrocarbon generation capacity.

2. The hydrocarbon origin of the Jurassic Xishanyao Formation is the same as that of the Carboniferous in well DN7. It should be the product of the mature stage of the Carboniferous Formation. The carbon isotope values of methane $\delta^{13}C$ and ethane in the Jurassic Xishanyao Formation are the same as the carbon isotope characteristics of Carboniferous natural gas in the Kelameili Gas Field are humic organic products from the Carboniferous.

3. The hydrocarbon of the Permian Wutonggou Formation in well DN8 originates from the Permian Pingdiquan Formation. The deep strata in the Northeast of the Dongdaohaizi Depression should be a good exploration area for hydrocarbon.
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