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Characteristics and Origin of Natural Gas in Yongfeng Sub-Sag of Bogda Mountain Front Belt

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Abstract: By systematically analyzing the natural gas composition, carbon isotopes, and source rock characteristics in the Yongfeng sub-sag of the Bogda Mountain front belt, natural gas characteristics were determined, and the genetic types and sources of natural gas were investigated. The research results indicate that methane is the main component of natural gas in the Yongfeng sub-sag, with low levels of heavy hydrocarbons and a high drying coefficient. These characteristics make it dry gas, which refers to natural gas with a methane content of over 95%. The ethane carbon isotope $\delta^{13}C_2$ of natural gas is −28.5‰ and belongs to oil type gas. The methane carbon isotope $\delta^{13}C_1$ of natural gas is −58.6‰~−59.4‰, has a relatively depleted methane carbon isotope value, shows significant differences from the surrounding natural gas methane carbon isotope, and belongs to the category of biogenic gas. The Permian Lucaogou Formation is the main source rock in the study area, with good organic matter abundance. The microscopic components of kerogen are mainly composed of sapropelic formations and the organic matter type is I–II$_1$. The source rock has a high maturity and has reached the mature stage, mainly consisting of oil and wet gas. The ethane carbon isotope of natural gas in the Yongfeng sub-sag shows as oil type gas, which is consistent with the kerogen type of the Lucaogou Formation source rocks, indicating that the natural gas mainly comes from the Lucaogou Formation source rocks. Based on comprehensive data and information on natural gas composition, carbon isotopes, and burial history of the source rocks, it is believed that some of the crude oil generated from the Lucaogou Formation in the early stage underwent biodegradation due to tectonic uplift, resulting in biogenic methane and the formation of crude oil biodegraded gas.

Keywords: natural gas composition; natural gas carbon isotope; biogenic gas; Yongfeng sub-sag; Bogda Mountain front belt

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1. Introduction

The oil and gas exploration results in the Junggar Basin show an obvious pattern of "more oil and less gas". The discovered natural gas fields are mostly small- and medium-sized ones, mainly located in Kelameili and in the southern margin of the Junggar Basin. From the perspective of the exploration level, the natural gas exploration rate in the basin is very low, only 9.0%, and is still in the early stages. In terms of geological conditions, three sets of large-scale gas source rocks are developed in the Junggar Basin, which have the material basis for the formation of large- and medium-sized gas fields, and have a great potential for natural gas exploration [1]. At present, the natural gas fields discovered in the southern margin of the Junggar Basin are mainly located in the central and western regions, including the Hutubi gas field, the Mahe gas field, etc. [2,3]. No large-scale gas field has been found in the Bogda Mountain front belt in the eastern region of the southern margin of the Junggar Basin. In the early stage, the exploration field in this area was dominated by unconventional shale oil. A billion-ton oil field was found in the Permian Lucaogou Formation of the Jimusar Sag in the northern margin of the Bogda Mountain. The main oil reservoir types are shale oil reservoirs with source reservoir integration or adjacent source-reservoirs [4]. Since 2017, the China Geological Survey has focused on conducting public welfare oil and gas surveys around the Bogda Mountain front belt. The Well Xjc 1 deployed at the northern margin of the Bogda Mountain front belt has obtained industrial gas flow in the Permian Lucaogou Formation and the Triassic Karamay Formation, opening the prelude to natural gas exploration in the Bogda Mountain front belt. In order to further expand the natural gas exploration scope of the Permian Lucaogou Formation, the deployment direction has shifted to the southwest. Well Xyd1 has been deployed in the Yongfeng sub-sag of the Chaiwopu sag on the southern margin of the Bogda Mountain front belt. The well has shown good oil and gas indications in the Lucaogou Formation. Three layers have been selected for oil and gas testing, all of which have obtained natural gas flow and have led to new discoveries in gas exploration. This is the first time that the Yongfeng sub-sag has obtained natural gas flow in the Permian Lucaogou Formation. In order to clarify the natural gas exploration prospects in the study area, this study systematically analyzed the geochemical characteristics of the Lucaogou Formation source rocks and the natural gas composition and carbon isotope of Well Xyd1, and compared them with the natural gas in neighboring areas, clarifying the genesis type and formation process of natural gas in the Yongfeng sub-sag. This study also provides a foundation for the study of natural gas reservoirs in the Bogda Mountain front belt, providing reference for the evaluation of natural gas resource potential and exploration deployment as a next step.

2. Regional Geological Condition

2.1. Structural Features

The Bogda Mountain front belt is located in the eastern section of the southern margin of the Junggar Basin, which is a famous oil and gas bearing basin in northwest China. The formation of the Bogda Mountain front belt is controlled by the uplift of the Bogda Mountain and the Ealing Hebergen Mountain, and has the characteristics of north–south zoning. Therefore, the Bogda Mountain front belt can be divided into two tectonic units, namely, the Fukang fault zone in the north and the Chaiwopu sag in the south. The Chaiwopu sag can be further divided into three secondary structural units from west to east, namely, the Yongfeng sub-sag, the Sangezhuang sub-bulge, and the Dabancheng sub-sag. The study area is located in the Yongfeng sub-sag, with an area of approximately 1500 km^2 (Figure 1).

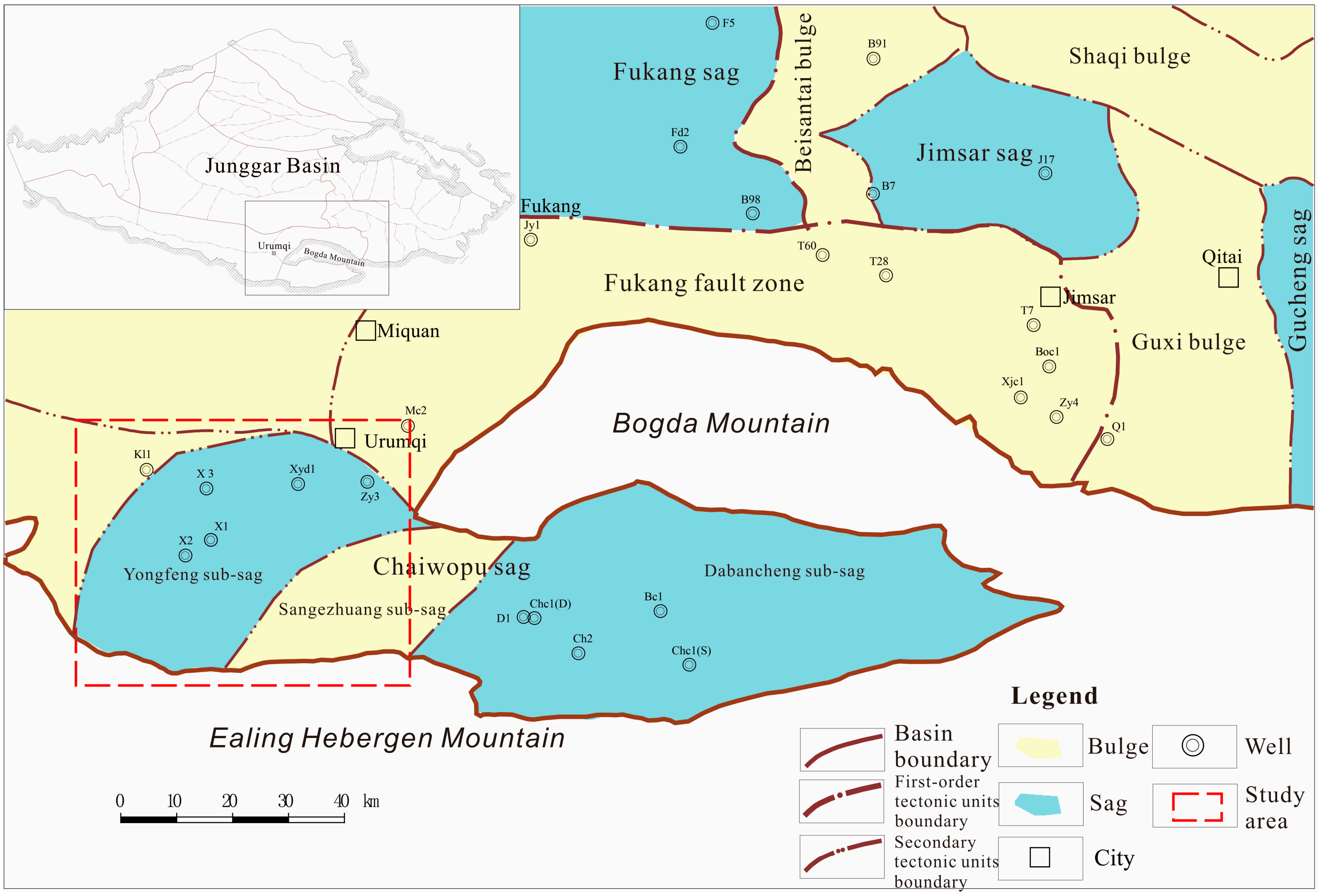

Figure 1. Location map of the study area.

2.2. Sedimentary Strata

The Chaiwopu sag is a superposition basin developed on the crystalline basement of the Precambrian and the folded basement of the Carboniferous. It has undergone five evolutionary stages in the later period, including the Early Middle Permian rift basin, the Late Permian Triassic compression flexural basin, the Jurassic weak extensional basin, the Cretaceous craton depression basin, and the Himalayan Period foreland basin. It has formed a thick sedimentary system including the Permian, Triassic, Jurassic, Paleogene, Neogene, and Quaternary. The residual strata in the main part of the Yongfeng sub-sag are mainly Permian and Jurassic, with the maximum thickness in the north. The Cretaceous, Paleogene, and Neogene have a large amount of erosion. Currently, except for the piedmont zone, most areas of the surface are covered by the Quaternary. The Lucaogou Formation of the Middle Permian in the Yongfeng sub-sag has developed high-quality lacustrine source rocks with a large sedimentary thickness, providing an important material basis for oil and gas accumulation in the study area. Multiple plays have been developed around this set of source rocks, among which the high-quality source rocks of the Lucaogou Formation and adjacent siltstones can form "self-generating and self-storing" shale oil and gas plays. This is also the most important exploration target layer for unconventional oil and gas reservoirs in the study area (Figure 2).

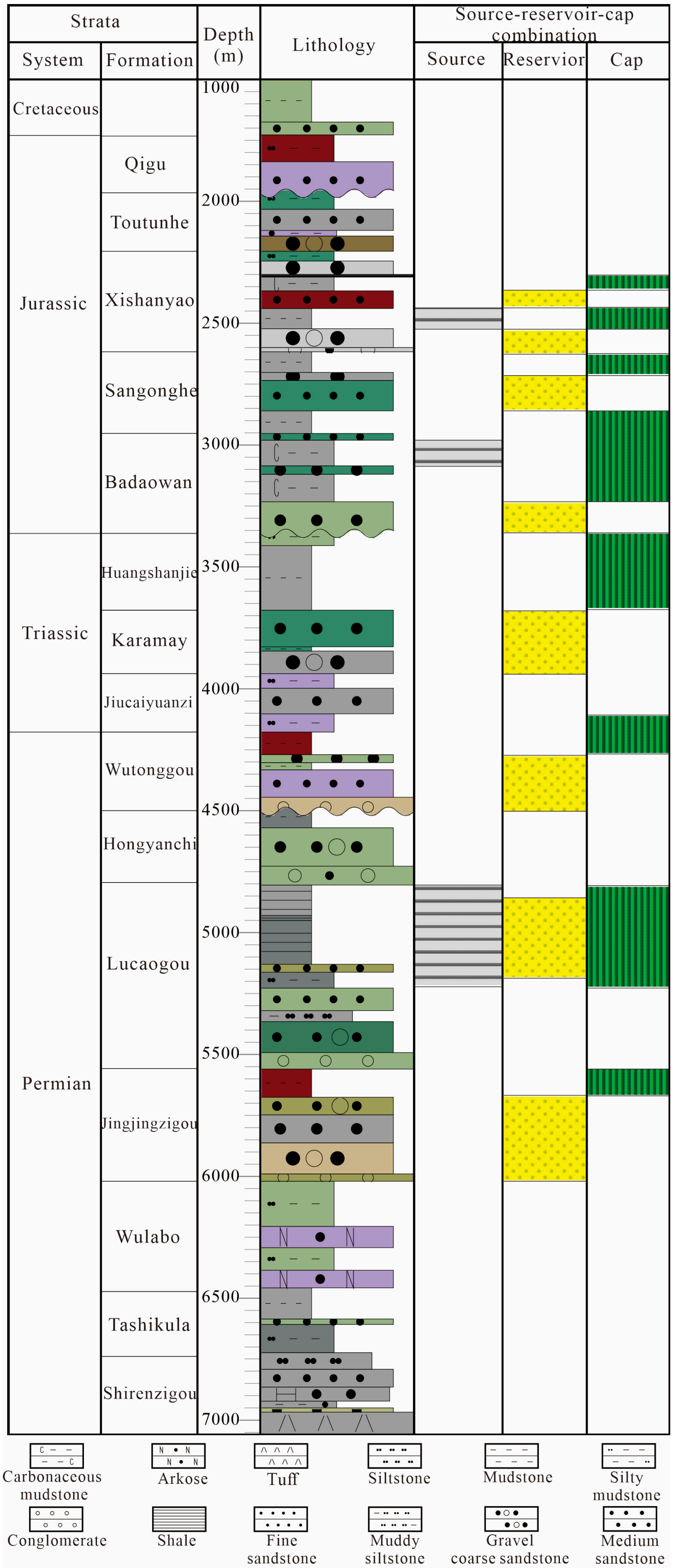

Figure 2. Column of source-reservoir-cap combination in the study area.

3. Sample Collection and Analysis

In this study, a total of 18 rock debris samples of the Lucaogou Formation source rocks were collected from Well Xyd1. The main focus of sample collection was to collect the black mudstone in the lower section of the Lucaogou Formation. The rock debris samples were concentrated at a depth range of 1874 m to 1754 m. The sampling interval was concentrated as much as possible in the high-quality source rock development section and evenly distributed. In total, 83 analysis tests were conducted on the 18 samples mentioned above, including 18 analyses of total organic carbon content (TOC) in the source rocks, 13 analyses of chloroform bitumen A, 13 analyses of rock-eval pyrolysis, and 13 analyses of kerogen vitrinite reflectance (R_o). The analysis of organic carbon in the source rocks was carried out using a CS-844 organic carbon analyzer. The sample was burned in a high-temperature oxygen stream to convert organic carbon into carbon dioxide. The total organic carbon (TOC) content was detected and provided using an infrared detector. The analysis of chloroform bitumen A was carried out using a YS fully automatic multifunctional extractor. The chloroform heated in a water bath at 78 °C was converted into vapor and then cooled through a condenser tube to form a liquid at the top of the sample, which was applied to the sample powder to dissolve the organic matter in the chloroform. By continuously repeating the distillation process, the organic matter in the sample was completely dissolved in the chloroform. Finally, the content of the organic matter that was dissolved in the chloroform from the solid sample was determined using the mass method. The rock-eval pyrolysis analysis of source rocks was carried out using the Rock Eval 6 type source rock evaluation instrument. The testing method involved initially heating the samples to 300 °C to measure the content of free soluble hydrocarbons (S_1), and subsequently heating the samples to 600 °C for the pyrolysis analysis. The content of pyrolysis hydrocarbons (S_2) was measured, and the temperature at which the yield of pyrolysis hydrocarbons (S_2) was highest was the peak temperature (T_{max}). The vitrinite reflectance measurement of kerogen was carried out using the MSP400 micro fluorescence spectrometer. The kerogen samples were bonded and polished with a binder to form a thin section, and then measured using a microphotometer under direct light with a wavelength of λ = (546 $\pm$ 5) nm. The microphotometer converted the reflected light intensity into an electric current through a photomultiplier tube. The output current of the sample was compared with the output current generated by a standard substance with known vitrinite reflectance under the same conditions, in order to obtain the vitrinite reflectance of the tested substance.

Fracturing and oil testing were conducted on three selected layers in the Lucaogou Formation of Well Xyd1, and natural gas flow was obtained in all layers. Two natural gas samples were collected at different time periods for each layer of testing and a total of six natural gas samples were collected for the three-layer testing. Natural gas composition was analyzed for the above-mentioned natural gas samples and two carbon isotope analyses were conducted for the upper two layers of the natural gas samples. Natural gas composition was analyzed using an HP 7890A gas chromatograph. The natural gas sample was injected into the gas chromatograph, and the content of each component was separated and determined by the difference in retention time of the different components in the fixed-phase column. The carbon isotope analysis of natural gas was carried out using a Delta V Ad-vantage isotope mass spectrometer. The testing method involved raising the temperature of the gas chromatograph oxidation furnace connected to the isotope mass spectrometer to 850 °C and passing helium gas through it. Natural gas was injected into a gas chromatograph for separation. The separated hydrocarbon components were oxidized by an oxidation furnace, producing CO_2 that entered an isotope mass spectrometer for detection.

4. Characteristics of Source Rocks

The Permian Lucaogou Formation around Bogda Mountain is a set of deep to semi-deep lacustrine sediments, whose thickness gradually increases near Bogda Mountain. The lithology is mainly rich in organic black to gray-black mudstone, interbedded with silty mudstone, cloudy mudstone, oil shale, etc. The thickness is relatively large, reaching more than 300 m, and it is the most important set of source rocks in the study area [2,5–8]. According to the evaluation criteria for organic matter abundance and the comprehensive evaluation of organic matter type and maturity of lacustrine mudstone source rocks, the Lucaogou Formation in the Yongfeng sub-sag is generally a high-quality lacustrine source rock. According to the testing and analysis of the shale in the Lucaogou Formation of Well Xyd1 (Table 1), the total organic carbon content (TOC) ranges from 0.95% to 6.94%, with an average of 3.49%; the S_1 ranges from 0.11 mg/g to 2.03 mg/g; the S_2 ranges from 1.03 mg/g to 29.11 mg/g; and the oil generation potential ($S_1 + S_2$) ranges from 1.42 mg/g to 29.11 mg/g, with an average of 11.16 mg/g. The chloroform bitumen A ranges from 0.0653% to 0.4937%, with an average of 0.2802%, indicating a relatively high organic matter abundance overall (Figure 3). The microscopic components of kerogen in the Lucaogou Formation source rocks are mainly composed of sapropelic material, which accounts for 60% to 80%, and the overall evaluation of organic matter types is mainly I–II_1. The T_{max} value is between 433 °C and 448 °C, and the R_o is between 1.15% and 1.39%, reaching the mature stage that is dominated by oil and wet gas generation.

Table 1. Organic geochemical characteristics of source rocks in the Lucaogou Formation of Well Xyd1.

Sample	Depth/m	TOC/%	Chloroform Bitumen A/%	S_1/mg/g	S_2/mg/g	$S_1 + S_2$/mg/g	T_{max}/°C	R_o/%
Xyd1-03	1874	0.95	0.0653	0.11	0.92	1.03	433	1.15
Xyd1-04	1981	1.91	0.153	0.47	3.7	4.17	445	1.2
Xyd1-05	2015	1.81	0.1576	0.69	4	4.69	444	1.19
Xyd1-06	2034	3.73	/	/	/	/	/	/
Xyd1-07	2043	6.54	0.3158	0.98	28.13	29.11	446	1.2
Xyd1-08	2067	4.2	/	/	/	/	/	/
Xyd1-09	2079	6.94	0.1976	0.99	25.33	26.32	445	1.15
Xyd1-10	2089	5.68	/	/	/	/	/	/
Xyd1-11	2107	3.07	0.1804	0.51	7.99	8.5	446	1.19
Xyd1-12	2111	2.16	/	/	/	/	/	/
Xyd1-13	2131	4.63	0.3247	1.05	12.52	13.57	448	1.33
Xyd1-14	2156	3.48	0.2601	0.91	11.28	12.19	445	1.23
Xyd1-15	2175	3.91	0.2874	0.83	12.32	13.15	447	1.36
Xyd1-16	2246	3.4	0.4937	2.03	10.63	12.66	443	1.39
Xyd1-17	2253	3.73	/	/	/	/	/	/
Xyd1-18	2309	2.35	0.425	1.74	5.21	6.95	443	1.39
Xyd1-19	2319	2.07	0.4461	1.73	4.5	6.23	442	1.34
Xyd1-20	2323	2.26	0.3357	1.76	4.8	6.56	439	1.37

The dark mudstone of the Lucaogou Formation in the Hongyanchi area near Yongfeng has a thickness of over 400 m, with the TOC ranging from 0.90% to 5.46%, with an average of 4.52%. The chloroform bitumen A ranges from 0.0611% to 0.2203%, averaging 0.15%. The $S_1 + S_2$ ranges from 1.42 mg/g to 36.62 mg/g, averaging 8.7 mg/g. The Lucaogou Formation in the area of Yaomo Mountain is mainly composed of dark gray, gray-black, black, and gray-brown mudstone; shale; oil shale; and limestone. The TOC ranges from

7.49% to 7.84%, with an average of 7.2%. The $S_1 + S_2$ ranges from 36.4 mg/g to 46.81 mg/g, with an average of 41 mg/g.

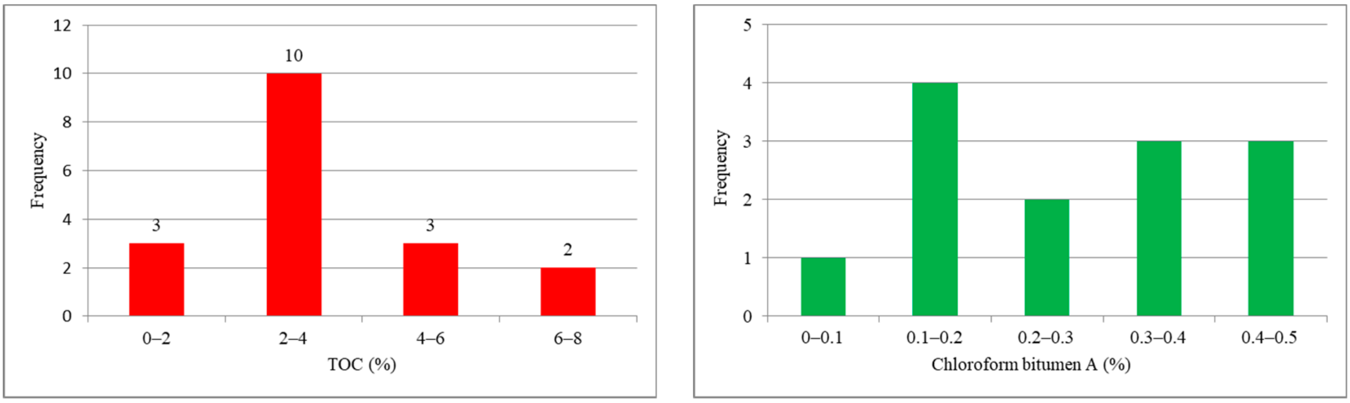

Figure 3. Histogram of TOC (**left**) and chloroform bitumen A (**right**) for source rocks in the Lucaogou Formation of Well Xyd1.

Overall, the source rocks of the Permian Lucaogou Formation in the study area and its surrounding areas have high organic matter abundance, good types, moderate maturity, and good hydrocarbon generation ability.

5. Geochemical Characteristics of Natural Gas

5.1. Characteristics of Natural Gas Composition

Composition is one of the geochemical features of natural gas. The factors that affect the variation of natural gas composition include the type and maturity of the source rock parent materials. Therefore, studying the characteristics and variation laws of natural gas composition plays an important role in the analysis of natural gas genesis and the study of gas accumulation laws.

The natural gas in the Yongfeng sub-sag is mainly composed of hydrocarbon gases, with significant differences in hydrocarbon gas content among different testing layers, ranging from 70.29% to 95.51%, with an average of 85.66%. Other gases are mainly nitrogen, which accounts for a high proportion at 4.49% to 29.71%, followed by carbon dioxide, which accounts for 0.1% to 0.2%. In hydrocarbon gases, there are significant differences in the content of different components; however, methane is the main component, accounting for 70.06% to 94.7%, with an average of 84.32%. The content of heavy hydrocarbon components (C_{2+}) is relatively low, ranging from 0.17% to 3.54%, with an average of 1.35%. The drying coefficients of natural gas are all greater than 0.96, ranging from 0.9628 to 0.9976, exhibiting typical dry gas characteristics (Table 2).

Table 2. Natural gas composition and carbon isotopes in the Lucaogou Formation of Well Xyd1.

Formation	Depth/m	Oil Testing Interval	Gas Composition/%								Drying Coefficient	$\delta^{13}C$/‰		
			C_1	C_2	C_3	nC_4	iC_4	nC_5	CO_2	N_2		C_1	C_2	C_3
Lucaogou Formation	2045–2072.5	S1	89.32	2.5	0.71	0.16	0.07	0.01	0.1	7.14	0.9628			
			91.97	2.57	0.72	0.16	0.07	0.02	0	4.49	0.9629			
	1804–1810.5	S2	87.87	0.19	0.07	0.02	0.01	0.03	0	11.81	0.9963	−58.62	−28.45	−27.18
			94.79	0.21	0.08	0.03	0.01	0.01	0.23	4.61	0.9963			
	1720–1776.3	S3	70.06	0.06	0.07	0.07	0.03	0	0	29.71	0.9967			
			71.9	0.04	0.06	0.05	0.02	0	0	27.94	0.9976	−59.42	/	/

The characteristics of the natural gas composition in the Yongfeng sub-sag are quite different from those in other areas in the southern margin of the Junggar Basin. The methane content of natural gas in the Anjihai, Khorgos, Manasi, Tugulu, and Hutubi areas in the central and western sections of the southern margin of the Junggar Basin generally ranges from 50% to 95%, and the natural gas is mainly wet gas [9,10].

5.2. Characteristics of Natural Gas Carbon Isotopes

The carbon isotope characteristics of natural gas are the most important identification indicators and methods for determining the genesis of natural gas [11].

The carbon isotope of ethane is mainly influenced by the type of hydrocarbon source rock parent material [12,13]. It is generally believed that the ethane carbon isotope value $\delta^{13}C_2 = -28‰$ is used as the boundary value for identifying oil type gas and coal type gas. If it is lower than this value, it indicates oil type gas, and if it is higher, it indicates coal type gas [14]. The majority of ethane carbon isotope $\delta^{13}C_2$ in the central and western parts of the southern margin of the Junggar Basin ranges from −28‰ to −22‰, which is characterized by coal type gas and mainly comes from Jurassic coal source rocks. However, the ethane carbon isotope $\delta^{13}C_2$ of natural gas from Well Xyd1 in the Yongfeng sub-sag is −28.45‰ (Table 2), which belongs to oil type gas associated with the parent material type of the Lucaogou Formation hydrocarbon source rock, and is different from the natural gas in the central and western regions of the southern margin of the Junggar Basin.

The methane carbon isotope is generally influenced by the degree of thermal evolution of the source rocks. Generally speaking, as the maturity of the source rocks increases, the methane carbon isotope of natural gas also increases [15]. The thermal methane carbon isotope value $\delta^{13}C_1$ is distributed between −30‰ and −45‰ [16], and the higher the degree of evolution, the larger the methane carbon isotope value. However, the biogenic methane carbon isotope value is relatively depleted, generally distributed between −75‰ and −45‰, and usually less than −55‰ [17,18]. Most natural gas methane carbon isotope $\delta^{13}C_1$ values in Anjihai, Khorgos, Manasi, and other areas in the central and western part of the southern margin of the Junggar Basin range from −35‰ to −33‰. The methane carbon isotope $\delta^{13}C_1$ of natural gas in Well Xyd1 in the Yongfeng sub-sag ranges from −58.62‰ to −59.42‰ (Table 2). The methane carbon isotope of natural gas is the lightest, which is significantly different from that of natural gas in the surrounding areas.

In addition, the distribution sequence of natural gas carbon isotope composition is also a method to identify organic origin natural gas [19,20]. In general, the different components of natural gas carbon isotopes usually show a positive sequence of becoming gradually heavier, that is, $\delta^{13}C_1 < \delta^{13}C_2 < \delta^{13}C_3$. From the distribution of natural gas carbon isotope components in different regions in the southern margin of the Junggar Basin, most of them show a positive sequence distribution, indicating that these natural gases are normal organic origin natural gas (Figure 4). However, the carbon isotope composition of natural gas in the Yongfeng sub-sag is lighter than that in other regions. From the perspective of ethane and propane carbon isotopes, the natural gas type in the Yongfeng sub-sag is oil type gas, which is different from that in the central and western regions of the southern margin of the Junggar Basin. However, most natural gas in the central and western regions of the southern margin of the Junggar Basin belongs to coal type gas or mixed gas (Figure 5) [9].

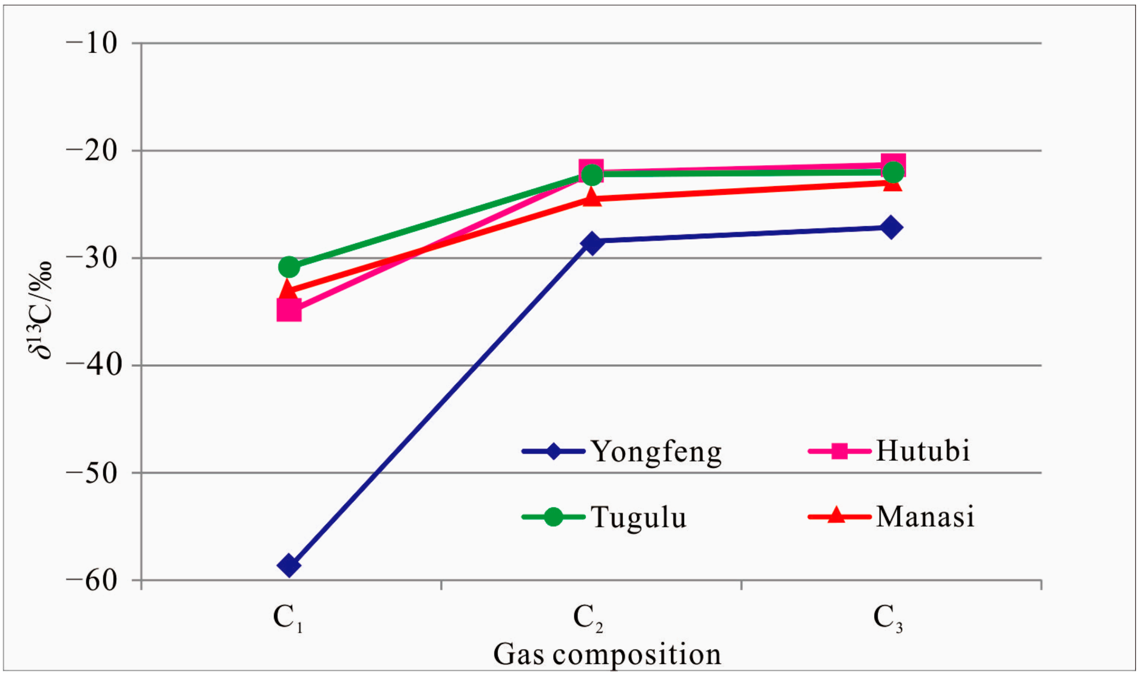

Figure 4. Distribution sequence of natural gas carbon isotope components in different areas in the southern margin of the Junggar Basin [9].

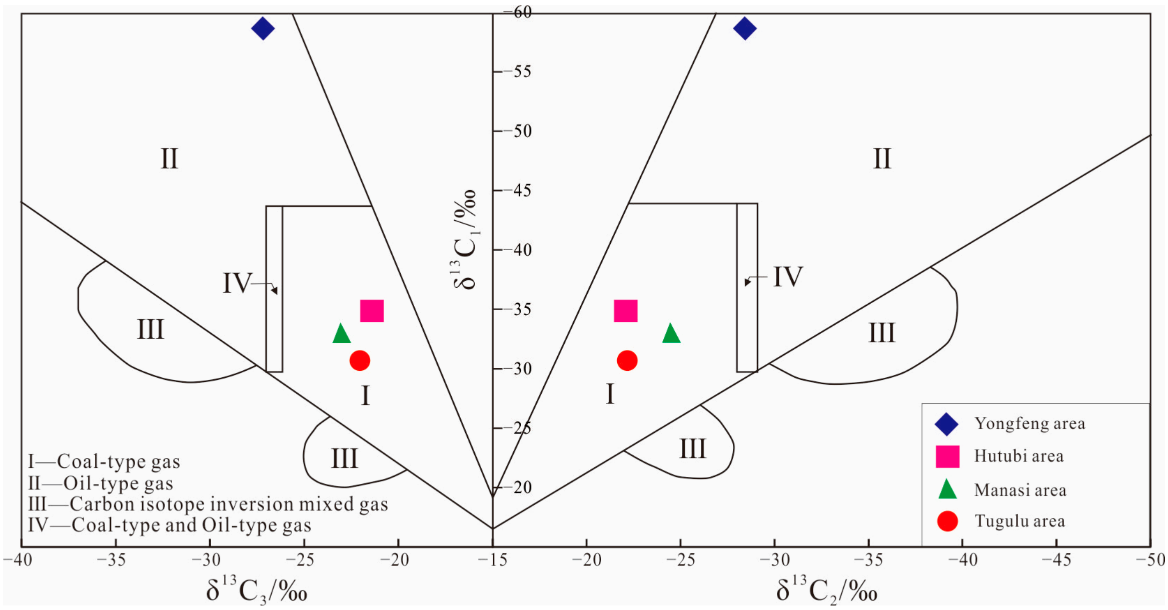

Figure 5. Identification diagram of natural gas $\delta^{13}C_1$—$\delta^{13}C_2$—$\delta^{13}C_3$ in different areas in the southern margin of the Junggar Basin [19,21].

5.3. Characteristics of Natural Gas Light Hydrocarbon Composition

The composition and content of light hydrocarbons in natural gas are influenced by geological conditions, maturity, and natural gas generation processes. Therefore, the composition of light hydrocarbons plays an important role in identifying the genetic type, maturity, gas source correlation, and natural gas accumulation of natural gas. By studying light hydrocarbons, we can better understand the generation mechanism and sources of natural gas, and provide guidance for the exploration and development of natural gas.

The composition of C_7 light hydrocarbons can distinguish the parent material types of natural gas [15,22]. Methylcyclohexane mainly comes from lignin, cellulose, and sugars in higher plants, and its thermodynamic properties are relatively stable, making it a good parameter for reflecting humic parent materials. Dimethylcyclopentane mainly comes from lipid compounds of aquatic organisms, which are sensitive to maturity and are indicators of sapropelic parent material. N-heptane mainly comes from algae and bacteria, and is sensitive to maturity, making it a good indicator of maturity. The relative content of n-heptane in oil type gas is greater than 30% and the relative content of methylcyclohexane is less than 70%. The relative content of n-heptane in coal type gas is less than 35% and the relative content of methylcyclohexane is greater than 50%. The natural gas from Well Xyd1 has a high content of n-heptane and a relatively low content of methylcyclohexane (Figure 6a), mainly sourced from algae and bacteria, and belongs to oil type gas.

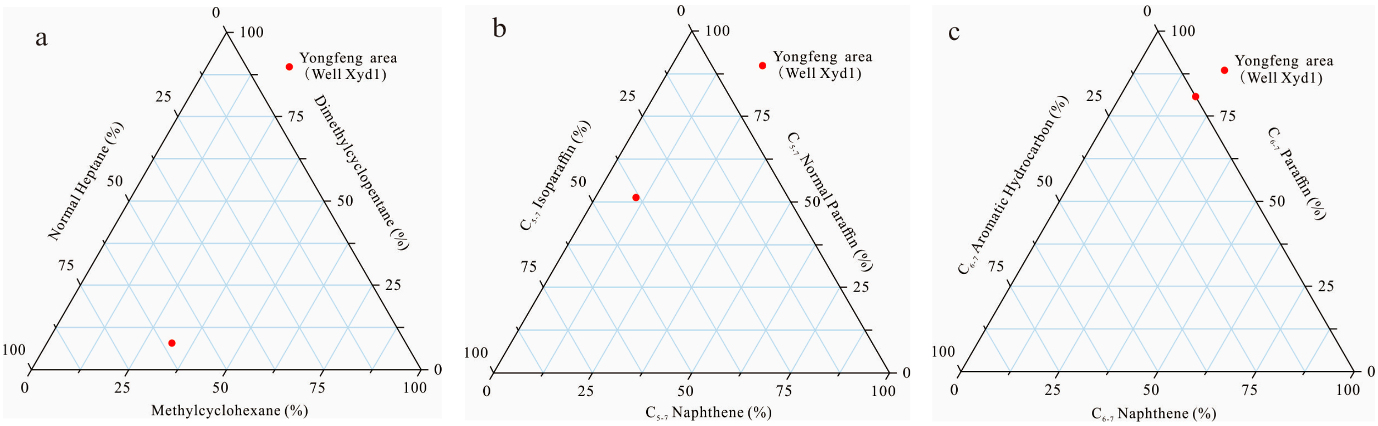

Figure 6. Characteristics of natural gas light hydrocarbon composition of Well Xyd1. (**a**) Triangle diagram of natural gas C_7 light hydrocarbons; (**b**) Triangle diagram of natural gas $C_{5–7}$ light hydrocarbons; (**c**) Triangle diagram of natural gas $C_{6–7}$ light hydrocarbons.

The relative content triangle diagram of C_5–C_7 light hydrocarbons is an important parameter commonly used to identify different types of natural gas. The light hydrocarbon components derived from sapropelic parent materials are rich in n-alkanes, while those derived from humic parent materials are rich in isoparaffins and aromatic hydrocarbons. The condensate rich in cycloalkanes is also an important characteristic of terrestrial parent materials [19,23]. Oil type gases generally have a relative content of C_5-C_7 n-alkanes greater than 30% [24]. The C_5–C_7 light hydrocarbon composition triangle diagram (Figure 6b) shows that the content of n-alkanes in the natural gas of Well Xyd1 is higher than 50%, indicating that it belongs to oil type gas.

The relative content of C_6–C_7 light hydrocarbons is greatly influenced by the type of organic matter and is also commonly used to identify natural gas of different genesis types [25]. Natural gas with the advantage of alkanes is mostly related to sapropelic source rocks, whereas natural gas with high aromatic hydrocarbon content is mostly related to coal-bearing source rocks. The relative content triangle diagram of C_6–C_7 light hydrocarbons shows that the natural gas from Well Xyd1 is mostly composed of alkanes that are mainly derived from sapropelic source rocks (Figure 6c).

6. Natural Gas Origin

6.1. Analysis of the Origin of Natural Gas

The composition and carbon isotope of natural gas are closely related to the sedimentary environment, organic matter type, and thermal evolution degree of the gas source material. The methane carbon isotope $\delta^{13}C_1$ and natural gas composition $C_1/(C_2 + C_3)$ values can be used to identify the origin of natural gas (Figure 7) [26,27].

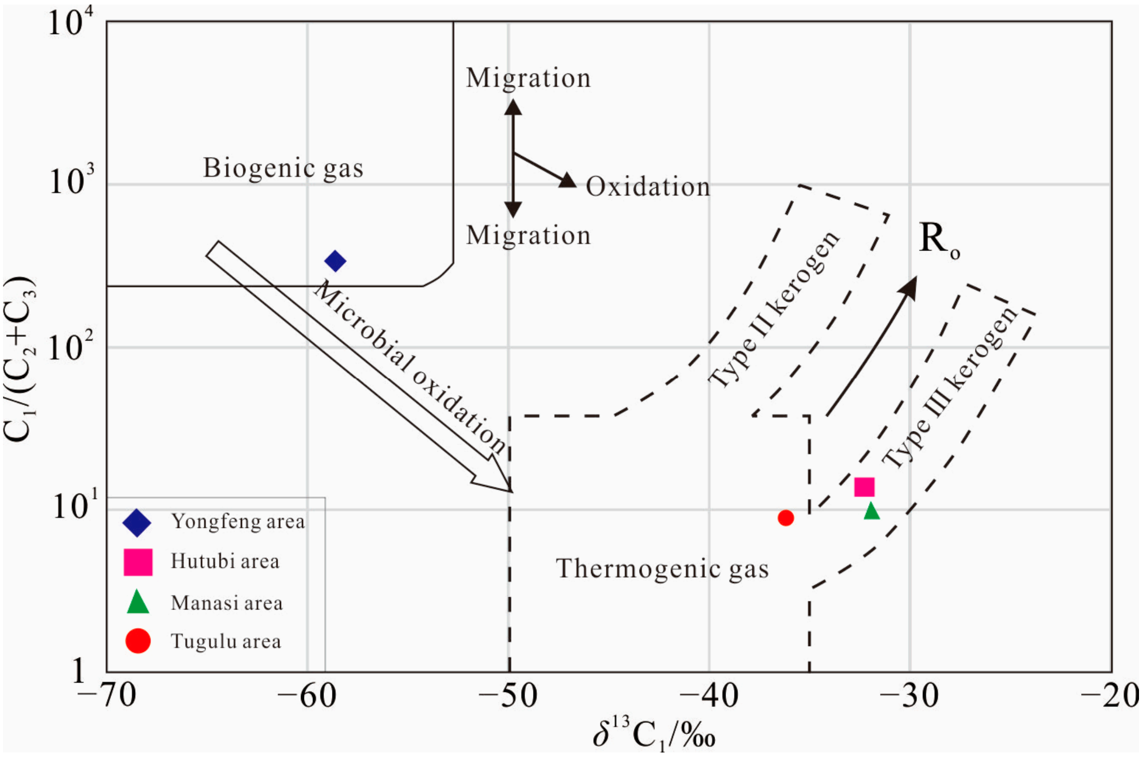

Figure 7. Genetic types of natural gas in different areas of the southern margin of the Junggar Basin [27].

The natural gas composition of the Yongfeng sub-sag shows that methane is the main hydrocarbon component, with a low, heavy hydrocarbon content and a high dryness coefficient. However, the R_o of the Permian Lucaogou Formation source rocks in the study area ranges from 1.1% to 1.25%. According to the thermal evolution stage, it should be in the stage of large-scale oil and wet gas generation. Obviously, there is a discrepancy between the drying coefficient of natural gas and the thermal evolution stage of the source rock. It is thought that the degree of natural gas dryness is not directly related to the thermal evolution of the source rock, and that natural gas does not come from the thermal evolution of the source rock to generate hydrocarbons. In general, the main product of natural gas generated by biological processes is methane that has very little heavy hydrocarbon content and has a drying coefficient that is generally greater than 0.95 [16,28–30]. From Well Xyd1, the drying coefficient of natural gas is relatively high, reaching more than 0.96, and the heavy hydrocarbon content is lower, generally ranging from 0.24% to 3.72%. The natural gas composition $C_1/(C_2 + C_3)$, with an average value of 329, is far higher than the natural gas composition $C_1/(C_2 + C_3)$ in Hutubi, Manasi, Tugulu, and other areas on the southern edge of the Junggar Basin. In addition, the methane carbon isotope of natural gas in the Yongfeng sub-sag is also significantly lighter than that in other areas in the southern margin of the Junggar Basin. Therefore, it is determined that the natural gas in the Yongfeng sub-sag is biogenic gas.

In addition to natural gas, a small amount of crude oil was also obtained in the Lucaogou Formation of Well Xyd1 during the oil testing process. The full analysis data of the crude oil showed that its density ranged from 0.89 to 0.90 g/cm^3 and its viscosity at 50 °C was 230–618 mPa.s. Based on these characteristics, it is classified as heavy oil according to the classification standard of crude oil. Therefore, it is thought that the natural gas of Well Xyd1 is a biological degradation gas of crude oil. This process refers to the source rock undergoing a certain degree of thermal evolution to reach the oil generation stage and generate crude oil. Due to factors such as later structural uplift, the crude oil is degraded by microorganisms to generate natural gas. During the process of crude oil degradation, natural gas becomes drier, with very little heavy hydrocarbon content, and the nitrogen content is usually higher than that of conventional natural gas reservoirs. In this process, residual oil will become heavier, so biodegradable gas is often associated with heavy oil [31–33].

6.2. Process of Oil and Gas Accumulation

The formation of oil and gas reservoirs in the study area generally went through three stages. The first stage corresponds to the main hydrocarbon generation and expulsion period of the Triassic to Jurassic period. Specifically, the source rocks of the Permian Lucaogou Formation entered the hydrocarbon generation period in the Triassic period. At this time, the maturity R_o of the source rocks could have reached 0.8%. As the strata continued to settle, the source rocks reached their maximum burial depth by the end of the Jurassic period, with a maturity R_o of up to 1.25%. At this time, large-scale hydrocarbon generation and expulsion began and the reservoirs began to form mainly generating oil and moisture. The second stage corresponds to the late Jurassic to Cretaceous period, during which time the Bogda Mountains began to experience large-scale tectonic uplift, leading to the stagnation of hydrocarbon generation in the source rocks. Additionally, the primary oil and gas reservoirs that formed during the first accumulation were destroyed and adjusted, resulting in the formation of secondary oil and gas reservoirs in some areas. The third stage corresponds to the Himalayan period, during which time the Bogda Mountain experienced its last large-scale uplift and formed a deep fault, providing a pathway for surface water carrying microorganisms to infiltrate oil and gas reservoirs. At suitable temperatures (measured in the reservoir at 40 °C to 50 °C), crude oil underwent biodegradation to form natural gas, which has continued until today.

This comprehensive analysis shows that the natural gas type of Well Xyd1 is crude oil biodegraded gas, mainly from the Lucaogou Formation source rocks. The source rocks of the Lucaogou Formation in the research area undergo certain thermal evolution to generate crude oil. Later, due to the uplift of the Bogda Mountain, the structure was uplifted, and under suitable geological conditions, biodegradation occurred to form natural gas.

7. Conclusions

1. The Permian Lucaogou Formation in the Yongfeng sub-sag and its surrounding areas has developed deep to semi-deep lacustrine facies, with the lithology mainly composed of organic rich black to gray-black mudstone. The source rocks are thick, with high organic matter abundance, good type, moderate maturity, and good hydrocarbon generation ability.

2. The Yongfeng sub-sag natural gas is mainly composed of hydrocarbon gases, while other gases are mainly nitrogen. For hydrocarbon gases, methane is the main component and the content of heavy hydrocarbon components (C_{2+}) is relatively low. The drying coefficients of natural gas are all greater than 0.96, showing typical dry gas characteristics. This is quite different from other natural gas components in the southern margin of the Junggar Basin.

3. The ethane carbon isotope $\delta^{13}C_2$ of natural gas is −28.45‰ and the methane carbon isotope $\delta^{13}C_1$ of natural gas ranges from −58.62‰ to −59.42‰ from Well Xyd1 in the Yongfeng sub-sag. The carbon isotope of natural gas is significantly lighter than in other areas. According to the carbon isotope and natural gas light hydrocarbon composition, the natural gas type in the Yongfeng sub-sag is oil type gas, which is different from that in the central and western regions of the southern margin of the Junggar Basin.

4. Based on comprehensive data and information on natural gas composition, carbon isotopes, the burial history of source rocks, and thermal history, it is believed that the natural gas in Well Xyd1 is mainly influenced by biological processes. The crude oil generated from the Lucaogou Formation source rocks in the early stage was partially biodegraded due to tectonic uplift, resulting in biogenic methane and the formation of crude oil biodegraded gas.

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