Organic Geochemistry and Oil-Source Correlation of Oil Seepages and Potential Source Rocks in Qiangtang Basin, China

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1. INTRODUCTION

The Angdarco paleo-reservoir belt from the Buqu Formation, located in the central South Qiangtang Depression, is one of the largest paleo-reservoirs in the Qiangtang Basin (Figure 1a,b). The paleo-reservoirs intermittently extended approximately 35 km from east to west and 1 km from north to south, and the area is approximately 35 km² (Figure 1c).1,2 Previous studies show that the paleo-reservoir formed from the early stage of the Late Jurassic to the Early Cretaceous was subsequently transformed, before being destroyed during the Himalayan Period.3 The main oil generating stage is approximately 150–140 Ma, and the structural traps were formed later than this stage. Previous researchers have mainly focused on the geological structure, depositional environment, hydrocarbon accumulations, and oil-source correlation of this paleo-reservoir belt.4−7 However, the oil source of the Angdarco paleo-reservoir is still controversial. Some researchers agree that the source rock of the Angdarco paleo-reservoir is marine oil shale based on the solid bitumen distributed in the paleo-reservoir belt.8,9 Jianzhong et al. resolved that the oil seepages of the paleo-reservoir belt show good affinity with the Upper Jurassic Suowa Formation and Middle Jurassic Xiali Formation shale.10 Nan et al. suggested that the oil of the Angdarco paleo-reservoir belt is mainly from the limestone of the Upper Jurassic Suowa Formation limestone and the shale of the Middle Jurassic Xiali Formation.11 Wang et al. believed that the shale of the Upper Triassic Xiaochaka Formation and the limestone of the Middle Jurassic Buqu Formation could be the main source rocks for the paleo-reservoir.12 These multiple results and debates are a likely consequence of the high maturity and severe biodegradation of the Angdarco paleo-reservoir belt.5−12

Due to the complex structure of the study area, the paleo-reservoir has experienced multiple periods of uplifting and exposure damage, some of the source parameters are distorted, and previous studies have not systematically studied and analyzed the oil source of the paleo-reservoir, which has not formed a unified understanding of the oil source. Therefore,
The understanding of hydrocarbon accumulation system in Qiangtang Basin is still not clear, and the oil source problem has always been the key scientific problem to determine the oil and gas exploration in the Qiangtang Basin. In this study, the biomarker compounds and carbon isotopic compositions of individual n-alkanes of oil seepages and potential source rocks, which are resistant to thermal degradation and biodegradation, were determined. The study aims to clarify the organic matter type, maturity, and depositional environment of the oil seepages and potential source rocks, and finally perform oil-source correlation analysis for the Angdarco paleo-reservoir belt. This oil-source comparison method minimizes the impact of biological and thermal degradation on samples, comprehensively and accurately acquires key parameters of biomarkers of potential source rocks and oil seepages, and carries out oil-source comparison analysis scientifically. This is the first time that this kind of oil-source correlation method has been used for the Angdarco paleo-reservoir, and most of the potential source rock and oil seepage samples were tested and analyzed systematically.

2. GEOLOGICAL SETTING

The Tibetan Plateau constitutes a series of continental blocks, which include the Kunlun-Qaidam, Hoh Xil, Qiangtang, and Lhasa terranes from north to south (Figure 1a). The Qiangtang Basin (terrane) is located in the central-northern part of the Tibetan Plateau, which is separated by the present-day Bangong Lake-Nujiang suture zone (BNSZ) to the south and Jinsha River suture zone (JSZ) to the north (Figure 1b). It is generally accepted that the Paleo-Tethys Ocean between the Hoh Xil and Qiangtang terranes opened in the early Carboniferous and closed during the Permian to Late Triassic. The Meso-Tethys Ocean, located in the present-day Bangong Lake–Nujiang suture zone (BNSZ), opened in the Triassic to Early Jurassic and closed in the Late Jurassic to Early Cretaceous. Based on geophysical data, the Qiangtang Basin can be divided into the South Qiangtang Depression, Central Uplift Belt, and North Qiangtang Depression (Figure 1b). Jurassic marine deposits are widely distributed in the Qiangtang Basin including the Quse (J₁q), Sewa (J₂s), Buqu (J₁b), Xiali (J₁x), and Suowa Formations (J₃s) (Figure 2). The Lower Jurassic Quse Formation is composed of shale, siltstone, mudstone, and marl intercalated with fine sandstone. The upper Middle Jurassic Sewa Formation is mainly composed of fine-grained clastic rocks interbedded with minor marls. Upward, the Middle Jurassic (Bathonian) Buqu Formation is characterized by a large set of carbonate rocks including limestone and dolomite, the Middle Jurassic (Callovian) Xiali Formation consists of fine-grained siliciclastic rocks interbedded with gypsum and limestone, and the Upper Jurassic Suowa Formation is composed of limestone interbedded with minor fine-grained clastic rocks.
The Angdarco paleo-reservoir belt is located in the center of the South Qiangtang Depression. The oil-bearing strata are generally distributed in the saccharoidal dolomite and laminar algal dolomite of the Buqu Formation, which were deposited in a restricted carbonate-platform environment. The Quse Formation oil shale, Buqu Formation marlstone, and Xiali Formation mudstone in the South Qiangtang Depression could be potential source rocks. The proven reserves of the Angdarco paleo-reservoir have been estimated to exceed 0.5 billion tons and could be the largest paleo-reservoir belt in Tibet to date. The main source rocks in the study area are the oil shale of the Quse Formation, the marlstone of the Buqu Formation, and mudstone of the Xiali Formation. The reservoir is saccharoidal dolomite of the Buqu Formation, and the cap rock is the upper dense limestone of the Buqu Formation, which formed a source–reservoir–cap rock assemblage of lower generation and upper storage.

3. SAMPLES AND METHODS

In this study, six oil seepage samples in the Angdarco paleo-reservoir belt were collected from the Bagedijiar (BG-3, BG-4, BG-5) and Rgaerbao (RG-3, RG-4, RG-5) sections (Figure 1c). In addition, 11 potential source rock samples near the Angdarco paleo-reservoir belt were collected from the Bilong Co (BP-1, BP-2, BP-3, BP-4), Quruiqianai (QR-3, QR-7, QR-11), and Haranonggen (HR-1, HR-3, HR-5, HR-10) sections.
| sample | 1    | 2    | 3    | 4    | 5    | 6    | 7    | 8    | 9    | 10   | 11   | 12   | 13   | 14   | 15   | 16   | 17   | 18   | 19   | 20   | 21   |
|--------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|------|
| HR-1   | 1.58 | 88.15| 0.53 | 0.39 | 0.12 | 2.64 | 1.80 | 0.64 |     |      |      |      |      |      |      |      |      |      |      |      |
| HR-3   | 1.55 | 0.70 | 1.18 | 0.42 |      |      |      |      |      |      |      |      |      |      |      |      |      |      |      |      |
| HR-5   | 1.49 | 0.62 | 0.86 | 0.41 |      |      |      |      |      |      |      |      |      |      |      |      |      |      |      |      |
| HR-10  | 1.38 | 11.28| 0.61 | 0.80 | 0.58 | 0.16 | 2.66 | 1.82 | 0.36 | 0.11 | 0.74 | 0.42 | 0.55 | 1.20 | 0.20 | 0.15 | 0.03 | 0.14 |      |
| QR-3   | 1.34 | 42.20| 0.73 | 0.89 | 0.21 | 0.03 | 2.36 | 0.98 | 0.64 | 0.43 | 0.13 | 0.85 | 0.46 | 0.55 | 1.24 | 0.63 | 0.19 | 0.19 | 0.04 | 0.12 |
| QR-7   | 1.34 | 28.06| 0.69 | 0.86 | 0.20 | 0.02 | 2.55 | 1.20 | 0.68 | 0.38 | 0.44 | 0.10 | 1.07 | 0.52 | 0.53 | 1.13 | 0.62 | 0.17 | 0.20 | 0.03 | 0.11 |
| QR-11  | 1.47 | 0.62 | 0.80 | 0.17 | 2.77 |      |      |      |      |      |      |      |      |      |      |      |      |      |      |      |
| BP-1   | 1.03 | 5.38 | 0.28 | 0.50 | 0.57 | 0.14 | 2.48 | 1.09 | 0.42 | 0.38 | 0.48 | 0.18 | 1.70 | 0.63 | 0.57 | 1.31 | 0.58 | 0.20 | 0.24 | 0.05 | 0.09 |
| BP-2   | 1.00 | 3.37 | 0.35 | 0.45 | 0.62 | 0.14 | 2.44 | 1.04 | 0.41 | 0.35 | 0.46 | 0.18 | 1.78 | 0.64 | 0.57 | 1.30 | 0.58 | 0.20 | 0.23 | 0.05 | 0.09 |
| BP-3   | 1.01 | 3.67 | 0.30 | 0.42 | 0.60 | 0.14 | 2.37 | 1.08 | 0.43 | 0.36 | 0.47 | 0.14 | 1.71 | 0.63 | 0.57 | 1.31 | 0.58 | 0.20 | 0.24 | 0.06 | 0.09 |
| BP-4   | 1.01 | 4.55 | 0.25 | 0.52 | 0.58 | 0.16 | 2.41 | 1.02 | 0.43 | 0.35 | 0.46 | 0.19 | 1.66 | 0.62 | 0.57 | 1.32 | 0.58 | 0.21 | 0.23 | 0.05 | 0.09 |
| BG-3   | 0.94 | 2.42 | 0.14 | 0.24 | 0.56 | 0.85 | 5.67 | 1.42 | 0.97 | 0.39 | 0.43 | 0.15 | 3.07 | 0.75 | 0.51 | 1.03 | 0.63 | 0.20 | 0.24 | 0.04 | 0.13 |
| BG-4   | 1.11 | 2.19 | 0.26 | 0.30 | 0.78 | 0.51 | 4.00 | 1.05 | 0.63 | 0.36 | 0.41 | 0.13 | 2.38 | 0.70 | 0.50 | 1.00 | 0.61 | 0.27 | 0.27 | 0.05 | 0.14 |
| RG-3   | 0.95 | 1.66 | 0.22 | 0.40 | 0.51 | 1.62 | 9.84 | 1.32 | 0.73 | 0.35 | 0.41 | 0.11 | 5.05 | 0.83 | 0.45 | 0.81 | 0.63 | 0.21 | 0.43 | 0.05 | 0.12 |
| RG-4   | 1.04 | 2.45 | 0.18 | 0.28 | 0.55 | 0.49 | 2.93 | 1.40 | 0.85 | 0.36 | 0.40 | 0.12 | 1.27 | 0.56 | 0.53 | 1.12 | 0.59 | 0.23 | 0.15 | 0.04 | 0.14 |
| RG-5   | 1.04 | 2.24 | 0.20 | 0.27 | 0.64 | 0.45 | 3.25 | 1.07 | 0.81 | 0.38 | 0.40 | 0.11 | 1.07 | 0.52 | 0.51 | 1.03 | 0.58 | 0.25 | 0.15 | 0.04 | 0.14 |

*1: CPI; 2: (C<sub>21</sub> + C<sub>22</sub>)/(C<sub>23</sub> + C<sub>24</sub>); 3: Pr/nC<sub>15</sub>; 4: Ph/nC<sub>15</sub>; 5: Pr/Ph; 6: C<sub>24</sub>/C<sub>23</sub> tricyclic terpane; 7: C<sub>24</sub> (tetracyclic terpane)/C<sub>25</sub> tricyclic terpane; 8: C<sub>27</sub>/C<sub>25</sub>; 9: C<sub>28</sub>/C<sub>26</sub>; 10: ααα-29<sub>20</sub>s/(20s + 20R); 11: C<sub>29</sub>ββ/(ααα + βββ); 12: Rearranged sterane/Regular sterane; 13: T<sub>S</sub>/T<sub>M</sub>; 14: T<sub>S</sub>/(T<sub>S</sub> + T<sub>M</sub>); 15: 22S/(22S + 22R)-C<sub>31</sub>; 16: C<sub>31</sub> hopane S/R; 17: C<sub>32</sub> hopane S/(S + R); 18: gammacerane/hopane; 19: C<sub>29Ts</sub>/C<sub>30</sub> hopane; 20: C<sub>30</sub> diahopane/C<sub>30</sub> hopane; 21: bg<sub>30</sub> moretane/C<sub>30</sub> hopane.
oxidation oven is 880 °C, and the PDB precision is ±(0.2–1)‰.

4. RESULTS

4.1. Geochemical Characteristics of Oil Seepages. Organic geochemical results show that the percentage of saturated hydrocarbons in Middle Jurassic Buqu Formation oil seepages is 1.2–26.03 (average 12.84), that of aromatic hydrocarbons is 2.68–8.79 (avg. 5.66), that of NSO is 9.9–47.91 (avg. 27.91), and that of asphaltene is 24.66–68.66 (avg. 38.55).

4.1.1. Characteristics of n-Alkanes and Isoprenoids. The extracts of Middle Jurassic Buqu Formation oil seepages have relatively low CPI values, which are 0.91–1.04 (avg. 1.0). However, oil seepages have relatively high \((\text{C}_{21} + \text{C}_{22})/\text{C}_{28} \) and \(\text{C}_{29} \) ratios which range from 1.66 to 2.69 (avg. 2.28). The oil seepage Pr/Ph ratios are relatively low and vary from 0.51 to 0.78 (avg. 0.61), which shows phytane predominance. The \(\text{C}_{15}/\text{C}_{23} \) tricyclic terpane ratios of the oil seepages are also relatively low and fluctuate from 0.45 to 1.62, with an average of 0.84 (Table 1), and the TIC parameters showed the same trend characteristics.

4.1.2. Characteristics of Steranes and Hopanes. The oil seepages of the Buqu Formation have relatively high \(\text{aa} \alpha \text{aC}_{29} \) sterane 20S/(20R + 20S) and \(\text{C}_{29} \) sterane \(\beta \beta / (\alpha \alpha \alpha + \beta \beta \beta) \) ratios, which are 0.35–0.42 (avg. 0.38) and 0.40–0.43 (avg. 0.41), respectively. The rearranged sterane/regular sterane ratios of oil seepage samples are relatively low varying from 0.11 to 0.15 (avg. 0.13), which reflects that these oil seepage samples have low maturity. In this study, the \(T_i \) contents are slightly higher than those of \(T_m \) and the \(T_i/(T_i + T_m) \) ratios, varying between 0.52 and 0.83 (avg. 0.70), are relatively high. The configuration transformation parameters, such as 22S/(22S + 22R) \(\text{C}_{19}, \text{C}_{21} \) hopane \(S/R \), and \(\text{C}_{27} \) hopane \(S/(S + R) \) have ratio values of 0.45–0.53 (avg. 0.50), 0.81–1.12 (avg. 1.00), and 0.58–0.63 (avg. 0.61), respectively. All of these parameters indicate that oil seepage samples are in the low mature to mature stages. The \(\text{C}_{12}/(\text{C}_{22} + \text{C}_{22} + \text{C}_{22}) \) homohopane versus \(\text{C}_{29} \) 20s/(20s + 20r) sterane cross-plot also reflects that the oil seepage samples of the Buqu Formation have undergone a low maturity in the early mature stage. The \(\text{aa} \alpha \text{a} \alpha \text{aC}_{27} \) \(\text{C}_{29} \) regular sterane distribution patterns of oil seepage samples are “V”-shaped (Figure 3b, d).

Figure 3. Mass chromatogram \((m/z \ 217 \text{ and } m/z \ 191) \) of saturated hydrocarbons of oil seepages in the Angdarco area. (1: \(T_i \); 2: \(T_m \); 3: \(\text{C}_{29} \) Ts; 4: \(\text{C}_{30} \) hopane; 5: Gammaracene; 6: \(\text{C}_{27} \) 7: \(\text{C}_{29} \) 8: \(\text{C}_{29} \)).
The relative contents of C27 regular sterane are significantly lower than those of C29 regular sterane, and the C27/C29 ratios range from 1.05 to 1.44 (avg. 1.28). The gammacerane, C29-Ts, and C30-hopane contents in oil seepage samples are relatively low (Figure 3a-c). The gammacerane/C30-hopane, C29-Ts/C30-hopane, C30-dihopane/C30-hopane, and C30-moretane/C30-hopane contents of oil seepages are relatively low and range from 0.20 to 0.27 (avg. 0.23), 0.15 to 0.49 (avg. 0.29), 0.04 to 0.05 (avg. 0.04), and 0.12 to 0.14 (avg. 0.14), respectively.

4.2. Geochemical Characteristics of Potential Source Rocks. 4.2.1. Geochemical Characteristics of the Quse Formation Oil Shale. The percentage of saturated hydrocarbons in the Quse Formation oil shales is 11.22–21.57 (avg. 15.05), that of aromatic hydrocarbons is 18.08–28.83 (avg. 22.16), that of NSO is 20.3–25.48 (avg. 22.7), and that of asphaltene is 19.35–39.14 (avg. 31.14). The odd-carbon number predominance (CPI) of n-alkanes with high carbon is generally an indicator to discriminate the organic matter source and maturity. Values of CPI higher than 1.2 indicate that the organic matter is derived from a terrigenous source and is in the immature stage. The n-alkanes of the oil shale samples of the Quse Formation from the Bilong Co section are represented by C14–34 homolog with a maximum peak at CI6–17. The oil shale samples from the Quse Formation have low CPI values ranging from 1.00 to 1.03, with an average of 1.01, which may reflect the dominant marine organic matter source (CPI < 1.2). The (C21 + C22)/(C28 + C29) ratios can also be used to determine the origin of organic matter. Generally, terrestrial organic matter has low (C21 + C22)/(C28 + C29) ratios ranging between 0.6 and 1.2, while marine organic matter has relatively high ratios ranging between 1.5 and 5.0. The relatively high (C21 + C22)/(C28 + C29) ratios of the Quse Formation oil shale samples range between 3.37 and 5.38, with an average of 4.24, also supporting the marine organic matter source. The ratio of pristane and phytane (Pr/Ph) is a significant parameter and is widely used to discriminate between sedimentary environments and sources of organic matter. Generally, low Pr/Ph (Pr/Ph < 1) reflects a marine environment with anoxic conditions, intermediate Pr/Ph (1 ≤ Pr/Ph < 3) reveals a transitional environment with suboxic and oxic conditions, and high Pr/Ph (Pr/Ph > 3) reflects a terrigenous environment with oxic conditions. In addition, low Pr/Ph can also reflect the paleosalinity of the water column. Pr/Ph < 0.8 points to a reducing environment with high salinity. The Pr/Ph of the oil shale of the Quse Formation varies between 0.57 and 0.62, with an average of 0.59 (Table 1).

The low Pr/Ph reflects the phytane predominance of the Quse Formation oil shale, and the oil shale was mainly derived from marine organic matter in a reducing environment with high salinity. Moreover, the high C19/C23 ratios of the tricyclic terpanes can be indicative of terrigenous organic matter inputs. The C27 and C28 steranes come from marine organic and lacustrine algae, respectively, while C29 steranes are generally derived from land plant organic matter.

The relative abundances of aaaa20RC27–C29 of regular steranes are usually used to differentiate the type of organic matter. aaaa20RC27–C29 of regular sterane distribution patterns of oil shale samples from the Quse Formation show a V-shape (Figure 4b). In this study, the relative contents of C27 of regular sterane are roughly equivalent to C29, and C27/C29 ranges from 1.02 to 1.09 (avg. 1.06). However, the relative contents of C28 regular sterane are significantly lower than C29, which has C28/C29 varying between 0.41 and 0.43 (avg. 0.42).
A relatively high gammacerane abundance usually indicates a reducing and hypersaline environment. Fu et al. suggested that the gammacerane indices (gammacerane/C\textsubscript{30}hopane) of sediment extracts from marine, brackish, and freshwater environments are >0.4, 0.2−0.4, and <0.2, respectively.

Some biomarker compounds are usually used for maturity evaluation. The C\textsubscript{29}ββ/(αα+ββ) and ααC\textsubscript{29}20S/(20S+20R) ratios are believed to be efficient indicators of maturity. The Quse Formation oil shale samples have relatively high ααC\textsubscript{29}20S/(20S+20R) and C\textsubscript{29}-sterane ββ/(αα + ββ) ratios, which range from 0.35 to 0.38 (avg. 0.36) and 0.46 to 0.48 (avg. 0.47), respectively. The ratios of regular steranes/diasterene usually increase with increasing maturity, which is influenced by maturity and serious biodegradation. However, the samples show relatively low rearranged sterane/regular sterane ratios varying from 0.14 to 0.19 (avg. 0.17). In addition, other indices, such as T\textsubscript{s}/(T\textsubscript{s} + T\textsubscript{m}), C\textsubscript{30}-T\textsubscript{s}/C\textsubscript{30}-hopane, and 22S/(22S + 22R) homohopane ratios, are believed to be indicative of maturity and increase with increasing maturity. On the C\textsubscript{32}22S/(22S + 22R) homohopane versus C\textsubscript{29}20s/(20s + 20R) sterane cross-plot (Figure 5), all of the Quse Formation oil shale samples fall into the field of the early mature stage with low maturity. The T\textsubscript{s} contents in these oil shale samples are significantly higher than those of T\textsubscript{m} and show relatively high T\textsubscript{s}/(T\textsubscript{s} + T\textsubscript{m}) ratios ranging from 0.62 to 0.64 (avg. 0.63). The C\textsubscript{30}-moretane/C\textsubscript{30}-hopane ratio is also usually believed to indicate organic matter maturity, but it decreases with increasing maturity.

4.2.2. Geochemical Characteristics of the Marlstone of the Buqu Formation. The percentage of saturated hydrocarbons in marlstone of the Buqu Formation is 11.11−17.39 (avg. 13.5), that of aromatic hydrocarbons is 9.26−13.04 (avg. 11.11).
11.03), that of NSO is 36.0–44.44 (avg. 39.86), and of asphaltene is 29.63–40.0 (avg. 34.08). The \( n \)-alkanes \( C_{\text{max}} \) of extracts from the Middle Jurassic Buqu Formation marlstone samples are \( C_{29} \) and \( C_{31} \), showing even-carbon number predominance with moderate CPI values ranging from 1.34 to 1.47 (avg. 1.38). The Buqu Formation marlstone samples have significantly high \((C_{21} + C_{23})/(C_{28} + C_{29})\) ratios which vary between 28.1 and 42.2 (avg. 35.1). However, the samples show phytane predominance and have relatively low Pr/Ph ratios fluctuating from 0.17 to 0.21 (avg. 0.19). Similarly, relatively low \( C_{19}/C_{13} \) values of tricyclic terpane are present in these samples, ranging from 0.02 to 0.03 (Table 1).

The \( \text{aataa} \text{RC}_{27-23} \text{C}_{29} \) of regular sterane distribution patterns of the Buqu Formation marlstone samples are V-shaped (Figure 4d). In these samples, the relative contents of \( C_{27} \) regular sterane are slightly higher than that of \( C_{30} \) regular sterane, which has an average \( C_{27}/C_{30} \) ratio value of 1.09. The results indicated those the organic matter of marlstone was derived from mixed planktonic-bacterial matter (Figure 6). The marlstone samples show relatively low gammacerane contents (Figure 4c) and have a low gammacerane index (gammacerane/\( C_{30} \) hopane) ratios ranging from 0.17 to 0.19.

The \( \text{aataa} \text{C}_{29} \text{-sterane 20S/(20R + 20S)} \) and \( C_{30} \text{-sterane } \beta\beta/(\alpha\alpha + \beta\beta) \) of the Buqu Formation marlstone samples are relatively high, varying from 0.36 to 0.38 and 0.43 to 0.44, respectively. However, the ratios of rearranged sterane and regular sterane are relatively low varying from 0.10 to 0.13. The \( T_{m} \) contents are roughly equal to those of \( T_{m} \) and show moderate \( T_{m}/(T_{m} + T_{n}) \) ratios varying between 0.46 and 0.52, with an average of 0.48. The configuration transformation parameters, such as \( 22S/(22S + 22R) - C_{31} \), \( C_{31}-\text{hopane} \), and \( C_{31}-\text{hopane} \), vary from 0.35 to 0.37, 1.13 to 1.24, and 1.61 to 1.73, respectively. These maturity parameters indicate that the marlstone samples of the Buqu Formation are also in the low maturity to mature stage (Figure 5).

4.2.3. Geochemical Characteristics of Mudstone of the Xiali Formation. The percentage of saturated hydrocarbons in the mudstone of the Xiali Formation is 2.2–6.56 (avg. 4.06), that of aromatic hydrocarbons is 4.4–9.88 (avg. 7.42), that of NSO is 21.31–35.16 (avg. 27.85), and that of asphaltene is 50.62–59.49 (avg. 55.47). The \( n \)-alkanes \( C_{\text{max}} \) of mudstone samples of the Middle Jurassic Xiali Formation are \( C_{19} \), \( C_{21} \), and \( C_{23} \), which have moderate CPI values ranging from 1.38 to 1.58 (avg. 1.50). These samples have significantly wide and high \((C_{21} + C_{23})/(C_{28} + C_{29})\) ratios fluctuating from 11.3 to 88.2. The values of \( \text{Pr/Ph} \), \( \text{Ph/nC}_{17} \), and \( \text{Pr/Ph} \) are 0.53 to 0.70, 0.60 to 1.18, and 0.39 to 0.58, respectively. The values of \( C_{19}/C_{23} \) of tricyclic terpane are relatively low, ranging from 0.12 to 0.16 (Table 1). The \( \text{aataa} \text{RC}_{27-23} \text{C}_{29} \) of regular sterane distribution patterns of the Xiali Formation mudstone samples are "L"-shaped (Figure 4f). The relative contents of \( C_{27} \) regular sterane are significantly higher than \( C_{29} \), which has average values of \( C_{27}/C_{29} \) and \( C_{29}/C_{27} \) of 1.82 and 0.84, respectively. The Xiali Formation mudstone samples have low gammacerane contents (Figure 4e) and only sample HR-10 has a gammacerane to \( C_{30} \)-hopane ratio of 0.20.

Because biomarkers would be affected by different lithologies (such as mudstone, marlstone, and oil shale), the biomarker parameters of maturity and sedimentary environment were selected in this paper for oil-source correlation, using map and multifactor comparison method.

5. DISCUSSION

5.1. Indicative Significance of Biomarker Parameters. The low \( \text{Pr/Ph} \) and \( C_{19}/C_{23} \) tricyclic terpane ratios indicated that the oil seepages probably originated from marine source rocks and were deposited in an anoxic environment with high salinity. The results of \( \text{aataa} \text{RC}_{27-23} \text{C}_{29} \) relative contents showed that the organic matter of oil seepages was derived from mixed planktonic-bacterial matter (Figure 6). The results of hopanes indicated that oil seepages of the Buqu Formation were deposited in a marine environment with low salinity.

The oil shale of the Quse Formation has low \( C_{19}/C_{23} \) ranging from 0.14 to 0.16, with an average of 0.15 (Table 1), which indicates that the oil shale is also derived from marine organic matter. The results of \( \text{aataa} \text{RC}_{27-23} \text{C}_{29} \) relative contents suggested that the organic matter of the oil shale samples of the Quse Formation was derived from mixed planktonic-bacterial and plankton/algal matter (Figure 6). In addition, the gammacerane index is usually believed to be indicative of the water salinity of the depositional environment. The oil shale samples from the Quse Formation have a gammacerane/\( C_{30} \)-hopane range between 0.20 and 0.21, which reflects a brackish environment with low salinity, while these maturity parameters indicate that the oil shale samples from the Quse Formation are in the low mature to mature stage.

The \( \text{Pr/Ph} \) and \( C_{19}/C_{23} \) tricyclic terpane ratios of the marlstone of the Buqu Formation indicate that the samples were deposited in a marine environment with anoxic conditions, and its low gammacerane/\( C_{30} \) hopane values suggest a freshwater environment with low salinity. On the \( C_{31} -C_{23} \) homohopane versus \( C_{20} -C_{28} \) homohopane cross-plot (Figure 5), all of the Buqu Formation marlstone samples also show an early mature stage with low maturity.

The low \( C_{19}/C_{23} \) of tricyclic terpane and moderate \( \text{Pr/Ph} \) suggest that the Xiali Formation mudstones were deposited in an anoxic depositional environment with little terrestrial organic matter input, and the characteristics of the \( \text{aataa} \text{RC}_{27-23} \text{C}_{29} \) relative contents indicated that the organic matter of the potential Xiali Formation mudstones was derived from mixed planktonic-bacterial matter (Figure 6).
the Angdarco paleo-reservoir belt is the Quse Formation oil shale.

5.2.2. Correlogram Correlation of Biomarker Parameters. The ratios of rearranged sterane and regular sterane ratios and configuration transformation parameters can reveal the thermal maturity of potential source rocks and oil seepages. In the diagram of pristane/n-C\textsubscript{17}−phytane/n-C\textsubscript{18} (Figure 7), the potential source rocks and oil seepage samples are deposited in a reducing environment but have different maturities. The maturity of oil seepage samples of the Buqu Formation is slightly higher than that of the oil shale of the Quse Formation and significantly higher than that of the marlstone of the Buqu Formation and mudstone from the Xiali Formation.

The values of \(aaxC_{29}\) sterane \(20S/(20R + 20S)\) and \(C_{29}\) sterane \(\beta\beta/(\alpha\alpha + \beta\beta)\) of oil seepage samples from the Buqu Formation are medium, indicating that oil seepages are in the low mature to mature stage (Figure 8). The oil shale of the Quse Formation and the marlstone from the Buqu Formation have higher \(aaxC_{29}\) sterane \(20S/(20R + 20S)\) and \(C_{29}\) sterane \(\beta\beta/(\alpha\alpha + \beta\beta)\) than those of oil seepage samples of the Buqu Formation reflecting these potential source rocks are in the mature stage (Figure 8). However, the mudstone of the Xiali Formation has the lowest \(aaxC_{29}\) sterane \(20S/(20R + 20S)\) and \(C_{29}\) sterane \(\beta\beta/(\alpha\alpha + \beta\beta)\) ratios, which may indicate immature source rocks (Figure 8).

Generally, the maturity of oil is lower than or equal to that of source rocks.\(^\text{41}\) In this study, the maturity of mudstone samples

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**Figure 7.** Cross-correlation map of pristane/n-C\textsubscript{17} versus phytane/n-C\textsubscript{18} of the maturation of oil seepages and potential source rocks (criteria for immature, low mature, and mature stages are from Peters et al., 2005).

**Figure 8.** Correlogram correlation map of biomarker parameters for the maturation of oil seepages and potential source rocks (criteria for immature, low mature, and mature stages are from Peters et al., 2005).
from the Xiali Formation is lower than that of oil seepage samples from the Buqu Formation (Figures 7 and 8). Therefore, the mudstone samples of the Xiali Formation are not potential source rocks for these oil seepages. The depositional environment of the sediments can be accessed using the diagram of gammacerane/C_{30} hopane-\textit{aaa}(20R)-C_{27}/C_{29}. On the cross-plot, the oil seepages and potential source rocks reveal that the potential source rocks of the Middle Jurassic Buqu Formation have relatively lower gammacerane/C_{30} hopane ratios (Figure 9), indicating relatively lower-salinity environment, which is different from the oil seepages and potential source rocks of the Lower Jurassic Quse Formation.

The organic matter source and paleoredox of the water column can be evaluated using pristane/phytane-C_{27}/C_{29} regular sterane cross-plot. On the cross-plot, the oil seepage samples of the Buqu Formation and oil shale samples of the Quse Formation are clustered closely reflecting the mixed organic matter source and suboxic conditions (Figure 10).

However, the marlstone samples of the Buqu Formation are scattered from the field of oil seepage samples of the Buqu Formation and were deposited in an anoxic environment. Therefore, the marlstone samples of the Buqu Formation are not potential source rocks for these oil seepages.

5.2.3. Comparison of Terpene and Sterane. The compositions of biomarkers are dominated by numerous factors. The source of organic matter, depositional environment, and thermal maturity between oil seepage and potential source rocks show similar biomarker features if they have a good correlation. Therefore, 20 kinds of biomarkers were selected for oil-source correlation in this study, and these biomarkers can be used to indicate the thermal maturity, depositional environment, and organic matter sources (Table 1 and Figure 11).

The values of \((C_{21} + C_{22})/10(C_{28} + C_{29}), \text{ Pr}/nC_{17}, C_{27}/C_{29}, \text{ and } T_{s}/T_{m}\) of the oil seepage of the Buqu Formation and the oil shale of the Quse Formation are different from those of the marlstone of the Buqu Formation and the mudstone of the Xiali Formation (Figure 11). Therefore, the oil seepages may be related to the oil shale of the Quse Formation but have no obvious relationship with the marlstone of the Buqu Formation and the mudstone of the Xiali Formation based on the comprehensive multifactor correlation of biomarkers.

5.2.4. Comparison of Individual \(n\)-Alkanes \(\delta^{13}\)C. The \(\delta^{13}\)C values of individual \(n\)-alkanes of the Buqu Formation marlstone range from $-34.8$ to $-28.7\%_o$, and present a trend of increasing first and then decreasing with increasing carbon number. The change in \(\delta^{13}\)C values of the Buqu Formation marlstone was larger than those of the Quse Formation oil shale, Xiali Formation mudstone, and Buqu Formation oil seepage samples. The \(\delta^{13}\)C values of individual \(n\)-alkanes of the Xiali Formation mudstone vary from $-32.9$ to $-29.9\%_o$, which are relatively stable and lower than those of the Quse Formation oil shale and Buqu Formation oil seepage samples. The \(\delta^{13}\)C values of individual \(n\)-alkanes for C_{27}, C_{30}, and C_{32} in the Quse Formation oil shale are relatively high, which are similar to those of the Buqu Formation oil seepage. In...
addition, the $\delta^{13}C$ value distribution of individual $n$-alkanes shows a similar trend to the Buqu Formation oil seepage (Figure 12). These results also support that the Quse Formation oil shale may be the potential source rock of the Buqu Formation oil seepages.

The main research area of this study is located in Angdarco, Southern Qiangtang Basin, northern Tibet, China. The organic matter type, maturity, depositional environment of the oil seepages, and potential source rocks were discussed by analysis of biomarker parameters, and oil-source correlation analysis for the Angdarco paleo-reservoir. The area. In this paper, the characteristics of oil seedlings and source rock biomarker compounds in the Angdarco paleo-reservoir have been systematically and scientifically studied for the first time. It is proposed that the oil shale of the Lower Jurassic Quse Formation is the oil source of the paleo-reservoir, and the oil and gas migration route is determined. It is clarified that the Angdarco paleo-reservoir belongs to the “Downgenerated Up stored” reservoirs in which the Lower Jurassic Quse Formation is the source rock and the Middle Jurassic Buqu Formation is the reservoir. The research results provide a strong basis for the evaluation of oil and gas resources in the study area and the selection of exploration targets, which can promote oil and gas exploration in.

6. CONCLUSIONS

(1) The potential source rocks of the Bilong Co, Quruiqianai, and Haranonggen sections have different biomarker characteristics. The Quse Formation oil shale samples were distinguished from the Buqu Formation marlstone and Xiali Formation mudstone, which are characterized by lower $(C_{21} + C_{22})/10(C_{28} + C_{29})$, $P_t/nC_{15}$, $Ph/nC_{15}$, $P_3$: Pr/Ph; $P_6$: $C_{19}/C_{23}$ tricyclic terpane; $P_7$: $C_{27}/C_{29}$; $P_8$: $C_{28}/C_{30}$; $P_9$: $C_{29} \beta\beta/(\alpha\alpha + \beta\beta)$; $P_{10}$: Rearranged sterane/Regular sterane; $P_{11}$: $T_s/T_m$; $P_{12}$: $T_s/(T_s + T_m)$; $P_{13}$: $22S/(22S + 22R)$-C$_{31}$; $P_{14}$: $C_{29}$ moretane/$C_{30}$ hopane; (The parameter values are the average values of parameters for oil seepages and potential source rocks).

(2) The Quse Formation oil shale was deposited under suboxic conditions of littoral facies, while the Buqu Formation marlstone is in the low mature to mature stage and deposited in a marine environment with little terrigenous organic matter input. The Xiali Formation mudstones were in the immature to the low-maturity stage and were deposited in a low-salinity environment.

(3) The biomarker assemblage of the Buqu Formation oil seepages suggests that the oil was in the low mature to mature stage and was deposited in a suboxic littoral environment. The composition characteristics correlation of $n$-alkanes, terpenes, steranes, and $\delta^{13}C$ values of individual $n$-alkanes reveal that the Buqu Formation oil
seepages were mainly sourced from the Quse Formation oil shale.

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Notes
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