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*Research Article*

# Reservoir Overpressure in the Mahu Sag, Northwestern Junggar Basin, China: Characteristics and Controlling Factors

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Reservoirs with overpressure are of great importance for petroleum exploration where commercial production can be usually obtained. Studying the distribution characteristics and controlling factors of reservoir overpressure is crucial for further petroleum exploration. In this study, we investigate the vertical and planar distribution of reservoir overpressure in the Mahu sag, northwestern Junggar basin by analyzing measured pressure data from well testing of oil reservoirs. In the Baikouquan-Jiamuhe Formation, reservoir overpressure is widely distributed, and the pressure coefficient increases from the margin to the center of the sag and generally increases with the increasing altitude. Crossplot analysis of density and velocity in the Triassic strata and Permian Fengcheng Formation is conducted to further investigate the influence of undercompaction in the Mahu sag for the first time. The result suggests that undercompaction has little influence on reservoir overpressure, whereas fluid charging may play a vital role in the development of overpressure. Our research further conducted the analyses of distribution of source rocks and oil-source correlation. The results further confirmed that hydrocarbon generates from the Fengcheng Formation and charges into other reservoirs, suggesting that hydrocarbon generation and fluid charging are the main mechanism of reservoir overpressure.

## 1. Introduction

Reservoirs with abnormally high pressure are usually the most favorable targets for oil and gas exploration, and reservoir overpressure can enable commercial production from these reservoirs. Therefore, many researchers began to focus on reservoir overpressure, mainly investigating the distribution of reservoir overpressure [1, 2], the factors controlling the development of reservoir overpressure [3–6], the influence on reservoir quality [7–11], the relationship between overpressure and diagenesis, etc. [12–14].

In the Mahu sag, northwestern China, proved, probable, and possible reserves are about 30 billion tons. Reserves in the lower Triassic Baikouquan Formation, the upper Permian Wuerhe Formation, and the lower Permian Fengcheng Formation hold up to 20 billion tons. Petroleum exploration has revealed that reservoir overpressure is well developed in layers consisting of sandstones and conglomerates below the Triassic. Therefore, studying the characteristics and controlling factors of reservoir overpressure in the Mahu sag is extremely important for further petroleum exploration.

In previous studies, some researchers investigated the reservoir overpressure in the Jurassic strata in the central Junggar basin or other regions of the basin [15, 16], some focused solely on the reservoir overpressure in the Triassic strata in the Mahu sag, and the mechanism of overpressure in the Mahu sag remains controversial [17, 18]. Lacking enough data, few researchers paid attention to the reservoir overpressure through all the Triassic-Permian reservoirs in the Mahu sag. In recent years, with the increasing numbers of petroleum wells in the sag, more and more data are available for investigating the reservoir overpressure in the Mahu sag and adjacent areas. Besides, the acoustic velocity and the density method were proposed to determine the origin of overpressure in the early 21st century [19, 20]. In recent years, Zhao et al. [6] use this method to study the overpressure in the Qingshankou Formation in the Songliao basin and East China Sea basin. However, this method has not widely used in China, especially in the Junggar basin. In this study, 195 formation pressure data are analyzed from over 100 exploration wells in the Mahu sag and adjacent areas and utilized to investigate the characteristics of reservoir overpressure. Acoustic velocity and the density method, analyses of source rocks distribution, and oil-source correlation are conducted to further analyze the controlling factors of reservoir overpressure.

## 2. Geological Setting

The Junggar basin, located in the northwest part of China, covers an area of about 130000 $km^2$ (Figure 1(a)) [21]. The basin is a superimposed basin developed from late Paleozoic to Cenozoic [22, 23]. In late Carboniferous, the western Junggar basin experienced intense collision between the Junggar plate and the Kazakhstan plate [22, 24]. The thrusting and uplifting continued until late Permian, which also results in intense denudation. From the Triassic, the western Junggar basin entered a depression stage with uplift and denudation for several times [22, 25]. The Mahu sag is located in the northern portion of the Junggar basin, covering an area of 5000 $km^2$ (Figure 1(a)) [26]. The Mahu sag is bounded by Wuxia-Kebai fault belt to the north, Dabasong uplift to the south, Zhongguai uplift to the west, and Luliang uplift to the east (Figure 1(a)).

In the Mahu sag, sedimentary formations are widely distributed, including Carboniferous, Permian, Triassic, Jurassic, Cretaceous, and Cenozoic from oldest to youngest (Figure 1(b)) [27, 28]. The sag still receives sediments from the surrounding fault belts. The basin infill can be divided into four main units (Figure 1(b)): (1) the lower Carboniferous is considered a metamorphic basement of the Junggar basin and characterized by chaotic seismic reflection, which is dominated by volcanoes; (2) the upper Carboniferous unconformably overlies on the basement, made up of conglomerates, volcanoes interbed with mudstones or coals; (3) the lower and middle Permian is uplifted and denudated near the Wuxia-Kebai fault belt, chiefly consisting of conglomerates near the fault belt and sandstones and mudstones in the sag; (4) the upper Permian Upper Wuerhe Formation and its overlying formations sequentially overlap the underlying formations to the northwest in the sag.

The Jiamuhe Formation and the Fengcheng Formation are mainly the most important source rocks in the Mahu sag [29, 30]. The Jiamuhe Formation ($P_1j$) consists of volcanoes, conglomerates, sandstones, and mudstones (Figure 2). The Fengcheng Formation ($P_1f$) in the sag is dominated by dolomitic shales, dolomitic siltstones, and sandstones with alkaline minerals or evaporates. The Xiazijie Formation ($P_2x$) and Lower Wuerhe Formation ($P_2w$) are mainly characterized by sandstones with mudstones interbedded. The Upper Wuerhe Formation ($P_3w$) and Baikouquan Formation ($T_1b$) are mainly composed of coarse conglomerates and sandstones, the product of alluvial fan and fan delta facies [31, 32]. The Karamay Formation ($T_2k$) and Baijiantan Formation ($T_3b$) are featured by thick mudstones with thin sandstones interbedded, making them the most significant caprocks in the sag.

## 3. Reservoir Overpressure Data

Various methods for overpressure characterization are developed, including dimensionless overpressure, dynamic pressure increment, and pressure coefficient [33–36]. Pressure coefficient is defined as the ratio of initial reservoir pressure and the corresponding hydrostatic pressure, a parameter for judging whether the formation pressure is normal [36]. The formula is shown as $Pc = Pr/Pw = Pr/\rho gh$, where the Pc is the pressure coefficient, the Pr is the reservoir pressure, the Pw is the corresponding hydrostatic pressure, the $\rho$ is the density of formation water, and $h$ is the vertical depth of the stratum. In well oil testing, a pressure gauge is placed in the middle of the formation to be tested, and the upper and lower parts are sealed with a packer, respectively. When the formation pressure comes to stabilization, a pressure data is measured and recorded as the formation pressure. During this test, the formation is considered to be in an enclosed environment, and disturbance of fluid flows can be ignored. Therefore, in this study, the pressure coefficient for overpressure characterization is adopted. Reservoir pressure data are measured by an electronic pressure gauge during well testing of oil reservoirs, while the $h$ can be measured directly. The $\rho$ is taken as an average value of groundwater in the Mahu sag, 1.023 $g/cm^3$. Thus, 195 measured pressure coefficient data were obtained from over 100 wells in the Mahu sag and adjacent regions (Figure 3), including 24 data of Jurassic strata, 20 data of Baijiantan Formation and Karamay Formation, 84 data of Baikouquan Formation and Upper Wuerhe Formation, 26 data of Lower Wuerhe Formation and Xiazijie Formation, 24 data of Fengcheng Formation and Jiamuhe Formation, and 17 data of upper Carboniferous. In the oil and gas industry, it is generally considered that the pressure coefficient of overpressure is larger than 1.2 [37, 38].

## 4. Results

Among these data, all the data of Jurassic strata are lower than 1.2, meaning that the pressure of Jurassic strata is normal. Half of Baijiantan-Karamay Formation pressure coefficients are normal, and half of pressure coefficients are higher than 1.2, which means overpressure is locally developed in the Baijiantan-Karamay Formation. In the Baikouquan-Upper Wuerhe Formation, the altitude of data ranges from 1500 to 4500 m, and the value of pressure coefficient varies from 0.8 to 1.94. In the Lower Wuerhe-Xiazijie Formation, the altitude of data ranges from 2509 to 4600 m, and the value of pressure coefficient varies from 0.94 to 1.84. In the Fengcheng-Jiamuhe Formation, the altitude of data ranges from 2400 to 4600 m, and the value of pressure coefficient varies from 1.0 to 2.1, mainly distributes between 1.1-1.76 with a maximum value of pressure coefficient 2.14 in the Fengcheng Formation. The pressure coefficient of the upper

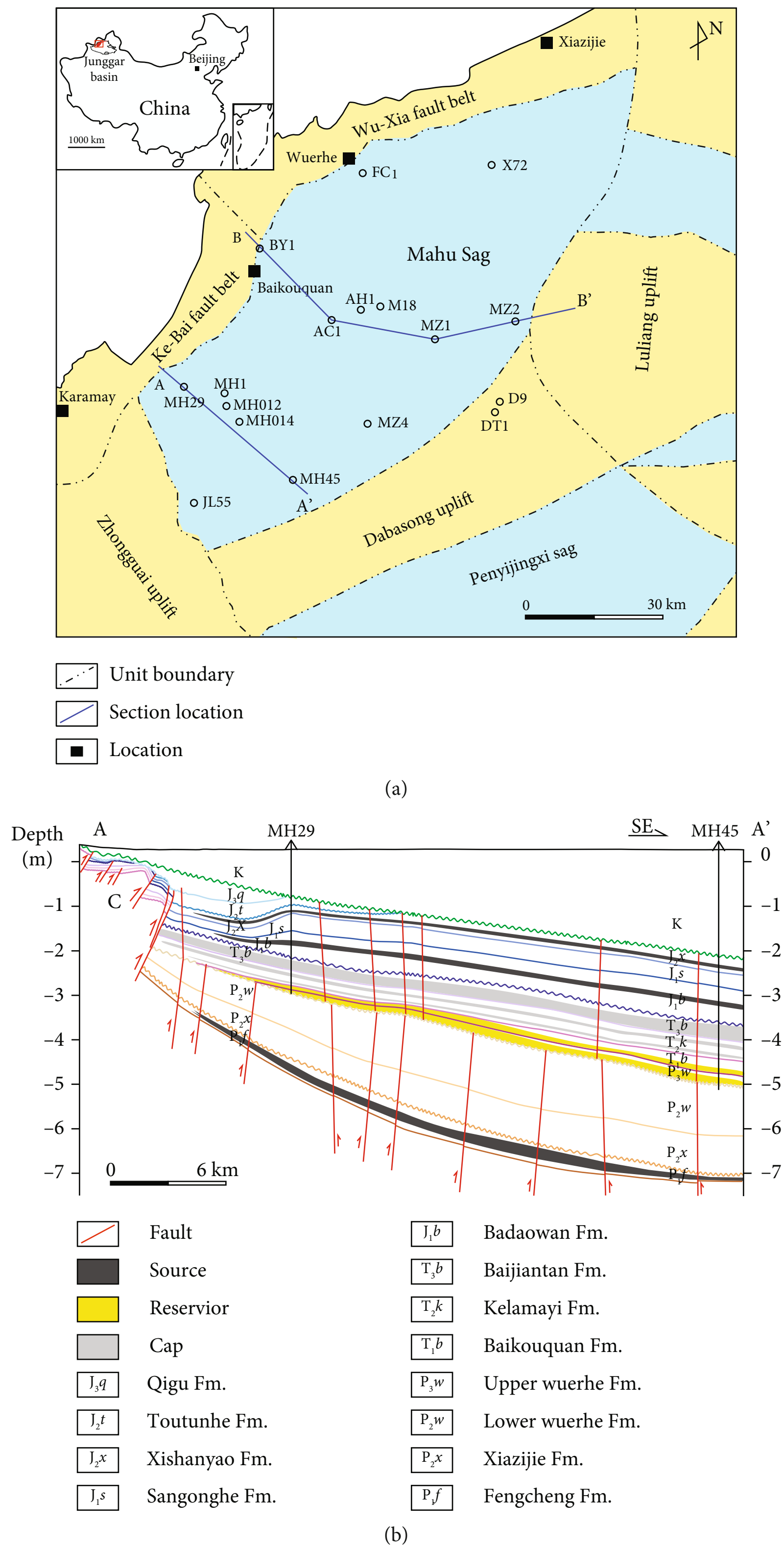


Figure 1: (a) Tectonic units and (b) a geological structure profile of the Mahu sag.

Carboniferous with altitude from 0-5500 m varies from 1.0 to 1.4. Noticeably, data of the upper Carboniferous mainly distribute in the northwestern margin of the sag (in or near the fault belt).

*4.1. Vertical Distribution of the Overpressure.* Based on these data, the relationships between pressure coefficients of different reservoirs and their altitudes are analyzed here (Figure 3). The pressure coefficients of all reservoirs are

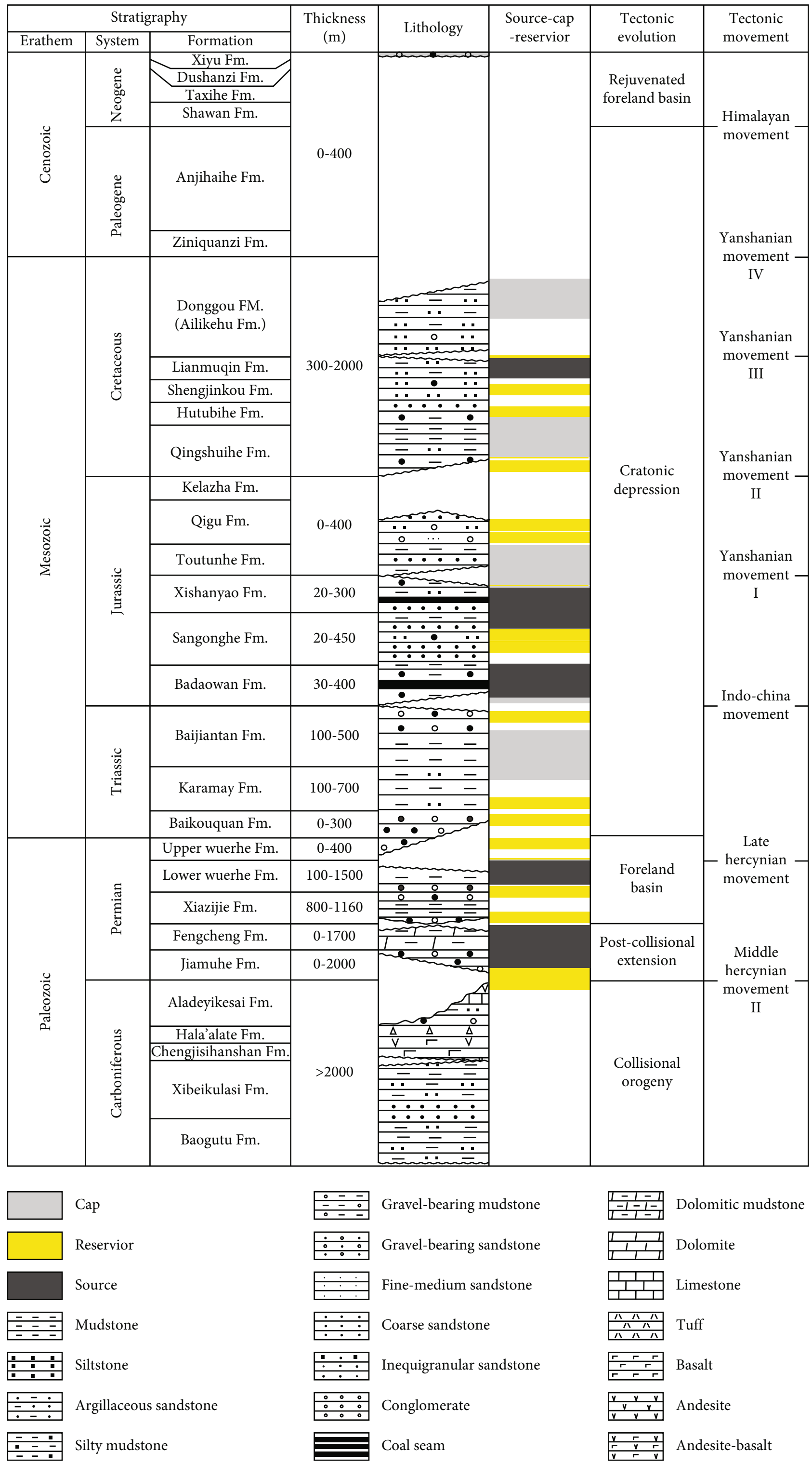


Figure 2: Tectonostratigraphic columns of the Mahu sag.

plotted on Figure 3 with different symbols. We can find that pressure coefficients of the Baijiantan-Karamay Formation range from 0.8 to 2.1 with altitude from 1100-4000 m, and the pressure coefficients exhibit a systematic increase with corresponding increase in altitude (Figure 3(b)). Besides, in the Baikouquan Formation and its underlying Permian strata ($T_1b$-$P_1j$), the pressure coefficients generally increase with the increasing altitude of reservoirs (Figure 3). Different from the overlying formations, the pressure coefficients of the upper Carboniferous have no obvious relationship with the altitude (Figure 3(f)). We also constructed a cross-section of pressure coefficient in the Mahu sag, from Well

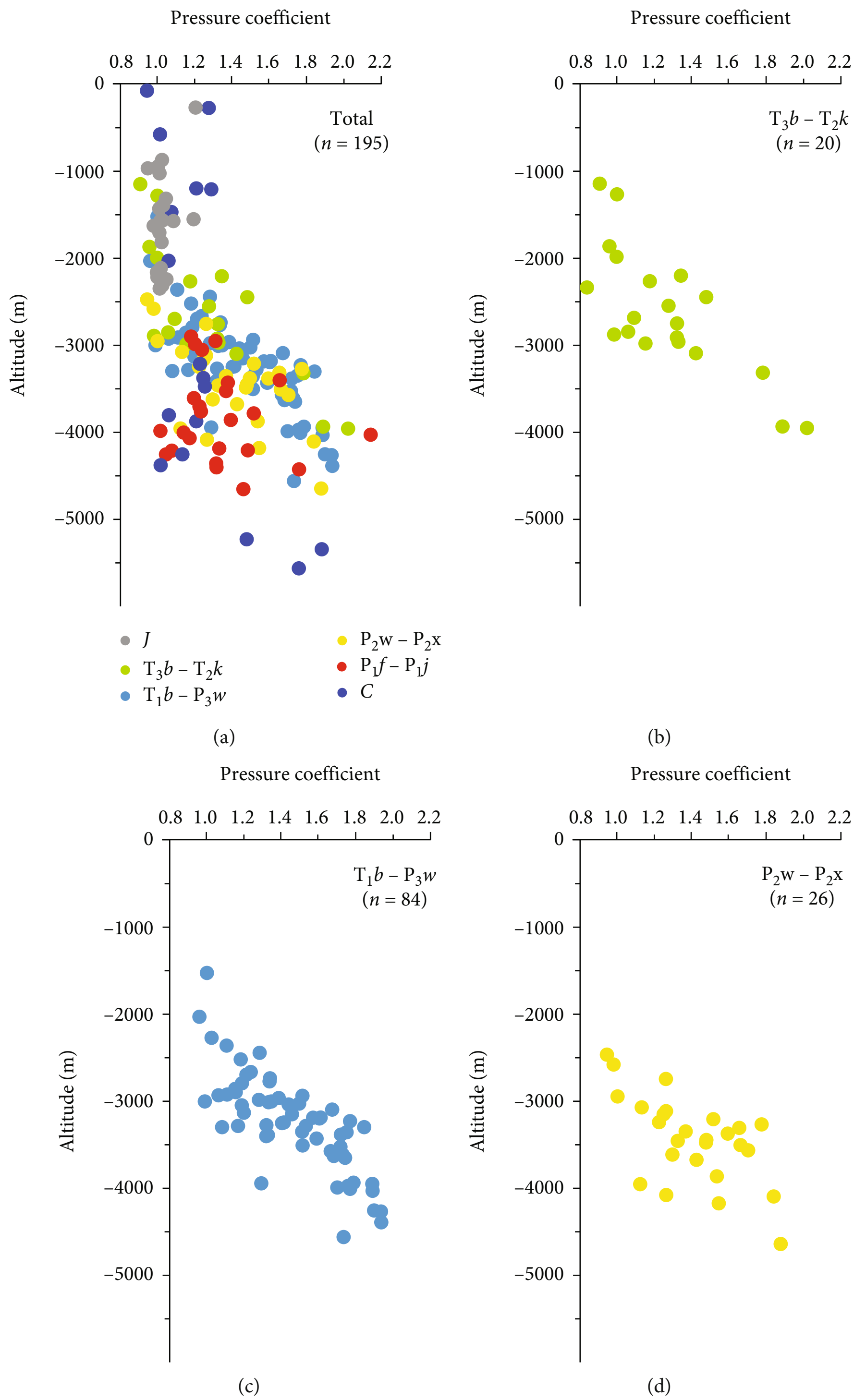


Figure 3: Continued.

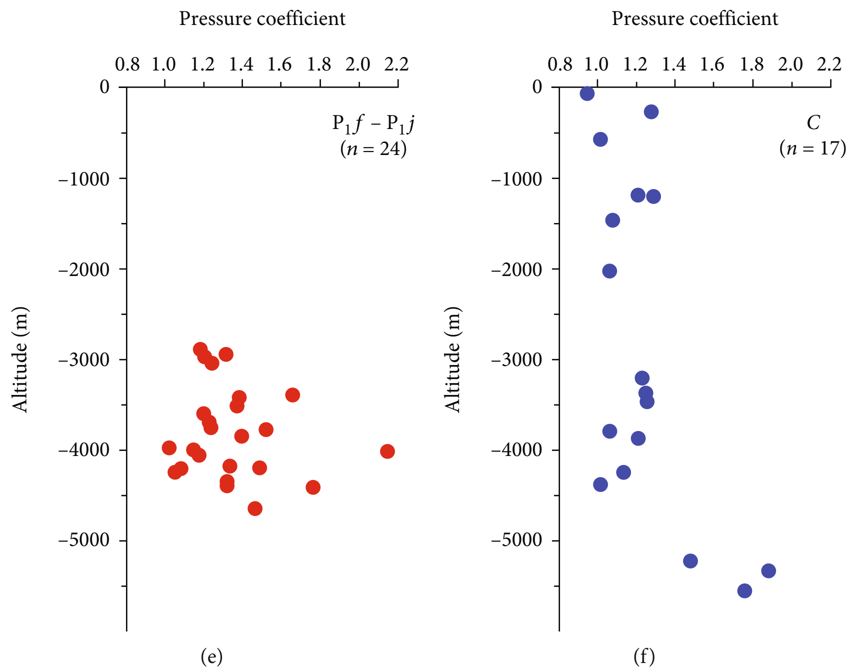


FIGURE 3: Relationship between measured pressure coefficient and altitude in the Mahu sag.

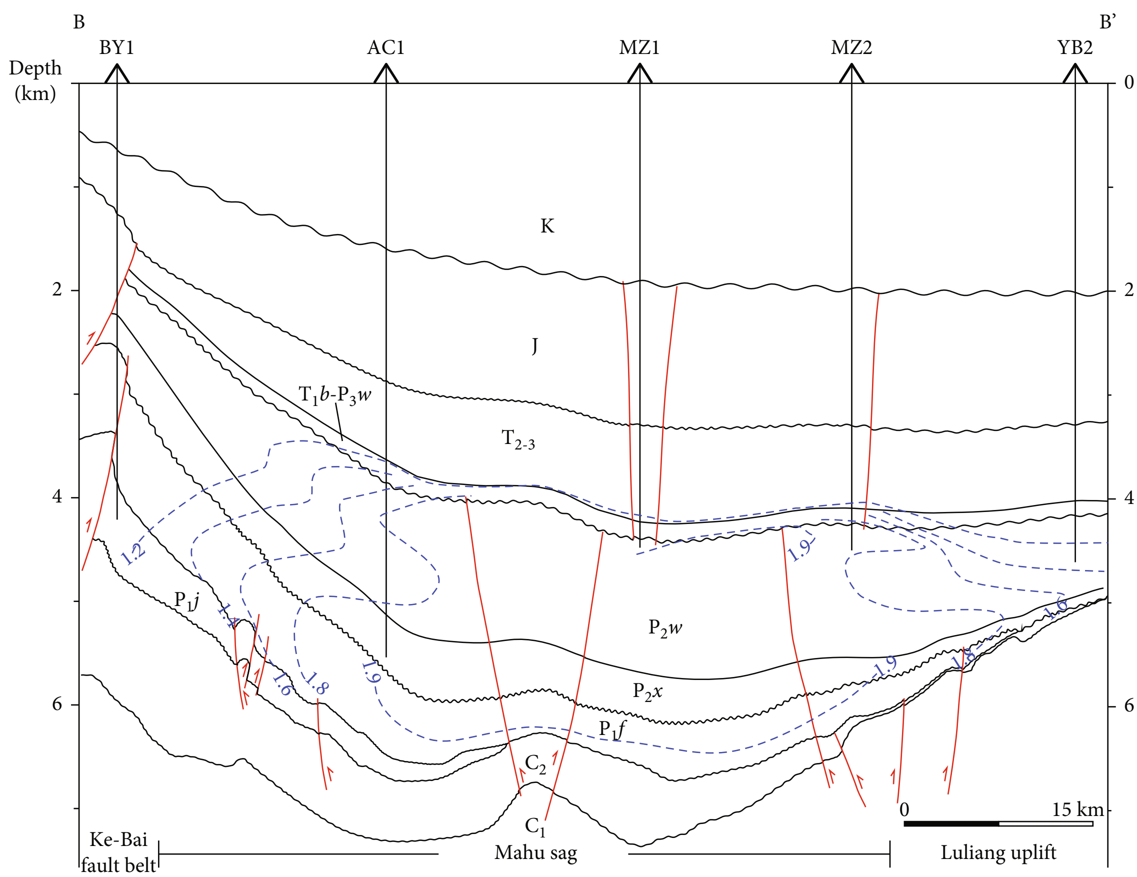


FIGURE 4: Pressure coefficient section in the Mahu sag (see section location in Figure 1(a)).

BY1 to Well MZ2 (Figure 4). It can be found that reservoir overpressure is widely developed in the sag, and the pressure coefficient increases from the margin to the center of the sag, e.g., from BY1 to MZ1, and increases with the increasing altitude from the Baikouquan Formation to Fengcheng Formation, e.g., Well AC1. Besides, the cross-section shows that

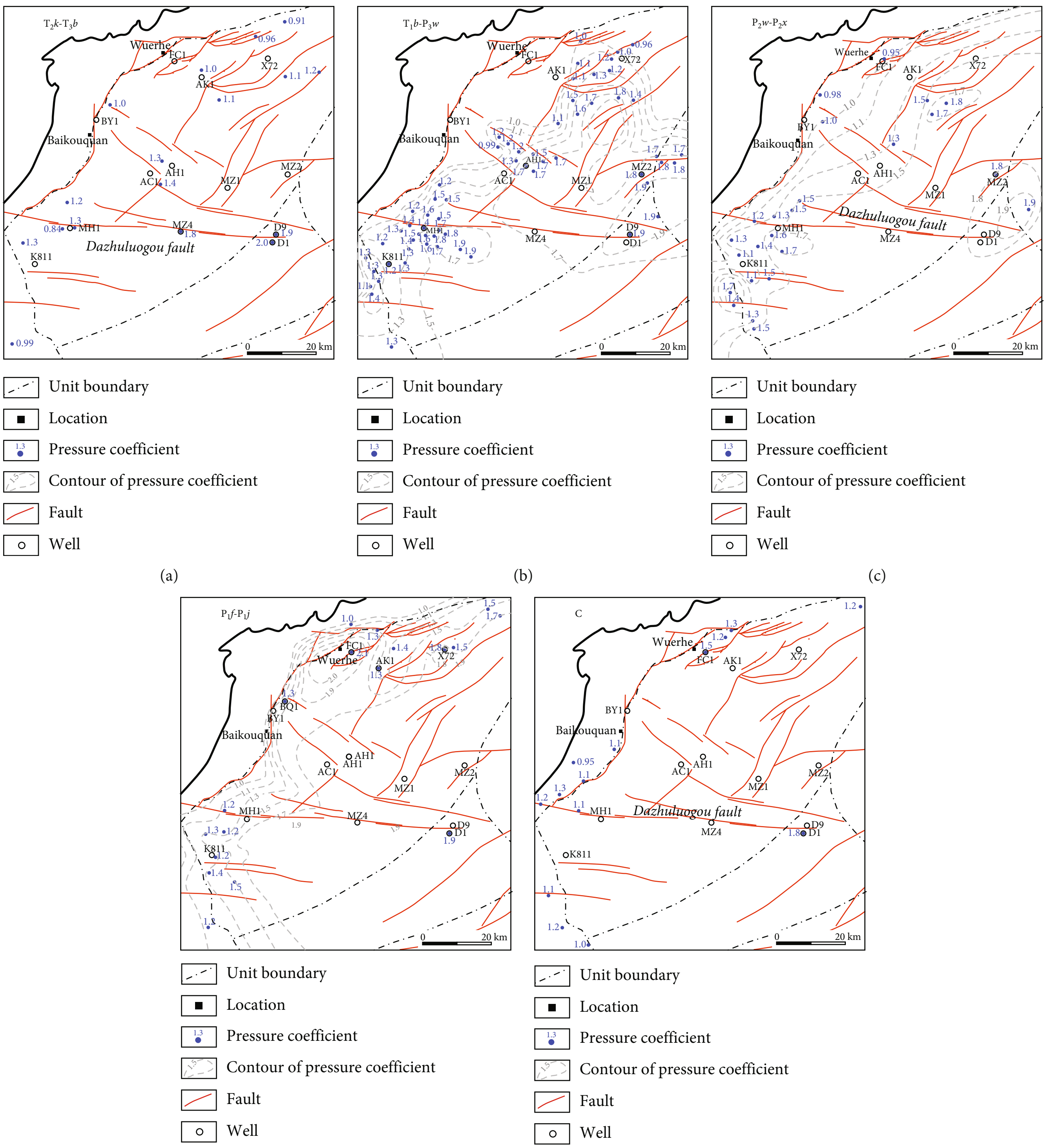


FIGURE 5: Planar distribution of reservoir overpressure in the (a) Baijiantan-Karamay Formation, (b) Baikouquan-Upper Wuerhe Formation, (c) Lower Wuerhe-Xiazijie Formation, (d) Fengcheng-Jiamuhe Formation, and (d) upper Carboniferous. (Note: considering the uneven distribution of data and limited distribution of overpressure in Baijiantan-Karamay Formation and upper Carboniferous, no contours are shown here.)

the Baikouquan-Upper Wuerhe Formation corresponds to the top surface of the reservoir overpressure, sealed by its overlying thick mudstones in the Baijiantan Formation (Figure 4).

*4.2. Planar Distribution of the Overpressure.* For a better understanding of the planar distribution, pressure coefficients are plotted in a planar graph (Figure 5). In the Baijiantan-Karamay Formation, reservoir overpressure occurs only at

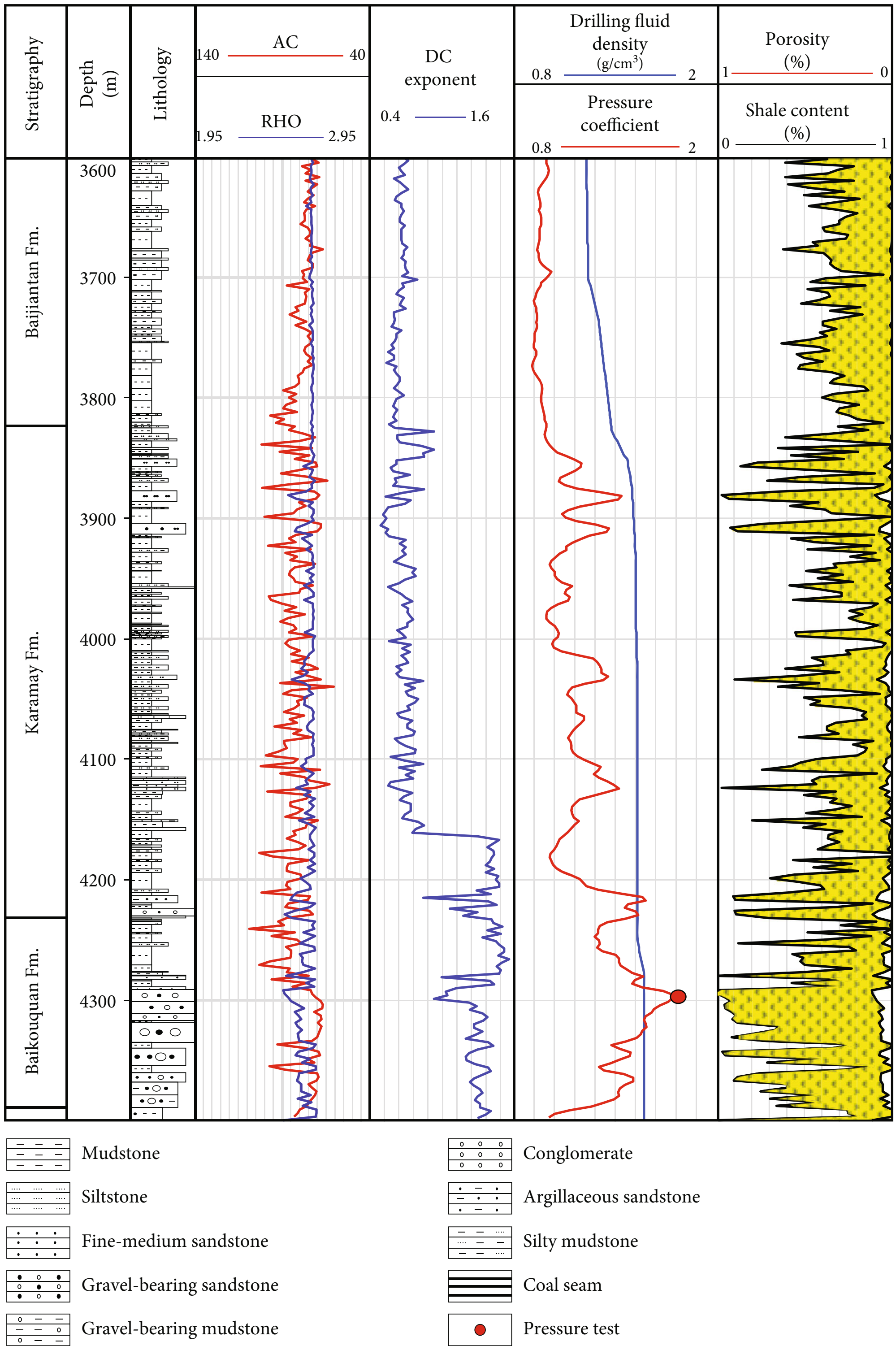


FIGURE 6: Triassic pressure analysis of Well D11 in the Mahu sag.

areas around Well MH1, Well AH1, Well MZ4, and Well D1, especially around Well D1 with a value of 2.0 (Figure 5(a)). The other areas are characterized by normal reservoir pressure coefficients. In the Baikouquan-Upper Wuerhe Formation (Figure 5(b)), reservoir overpressure exists in the areas around Well MH1, southeastern areas of Well AH1, and southwestern areas of X72, suggesting that three centers of reservoir overpressure develop in the sag. It can be found that pressure coefficients are higher in the sag than that in the slope near the fault belt and generally increase from the slope to the center of the sag (Figure 5(b)). In the Lower Wuerhe-Xiazijie Formation (Figure 5(c)), although most of data are limitedly distributed in the western margin of the sag, it can be found that pressure coefficients in the northern margin are lower

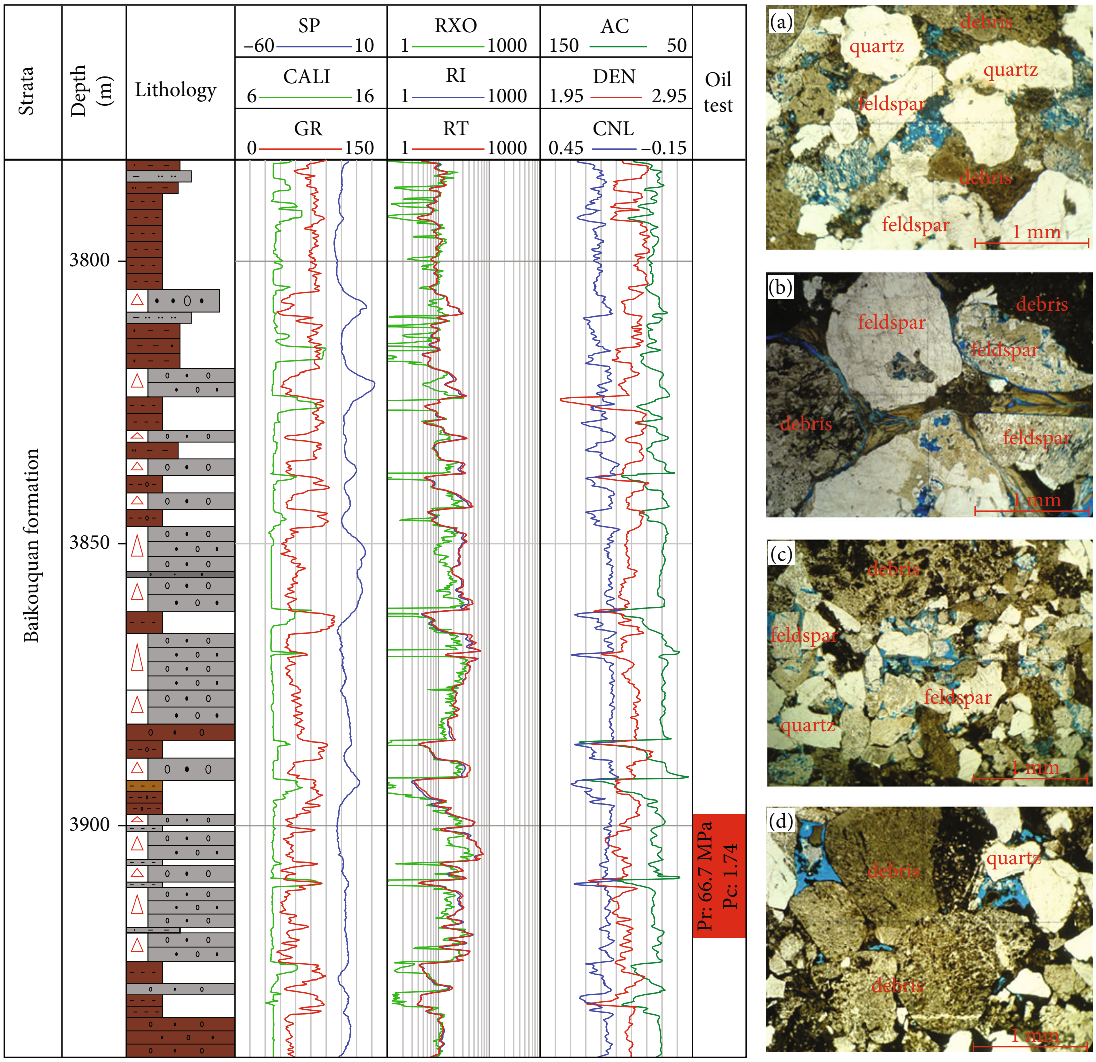


Figure 7: Synthesis columns of Well M18 and thin sections of the Baikouquan Formation: (a) conglomerate, 3904.9 m; (b) conglomerate, 3915.8 m; (c) coarse sandstone, 3917.3 m; and (d) conglomerate, 3923.1 m.

than 1.0 but generally larger than 1.2 in the sag with a maximum value of 1.84 in the area around Well MZ2. In the Fengcheng-Jiamuhe Formation, with a few exceptions, pressure coefficients are larger than 1.2 in the sag, indicating that reservoir overpressure is widely developed in these formations (Figure 5(d)). Noticeably, we can find that pressure coefficient is up to 2.1 in the area near Wuerhe (Well FC1), which means that a local center of reservoir overpressure develops in the margin of Mahu sag (Figure 5(d)). In the upper Carboniferous, pressure coefficients are limitedly distributed in the fault belt and northern margin of the sag (Figure 5(e)). However, it can be found that pressure coefficients are larger than 1.2 in the Wuerhe area while lower than 1.2 in other areas, revealing that reservoir overpressure distributes regionally in the northern margin of the sag.

Overall, reservoir overpressure is developed in the Triassic and its underlying strata in the Mahu sag. The reservoir overpressure of Baijiantan-Karamay Formation and upper Carboniferous is limited in regional areas while reservoir overpressure distributes widely in the Baikouquan-Jiamuhe Formation. Pressure coefficients in the Baijiantan-Jiamuhe Formation generally increase from the margin of the sag to the center of the sag and increase with the increase of altitude. However, pressure coefficients in the upper Carboniferous have little relationship with the altitude. The characteristics of reservoir overpressure in the Mahu sag are analyzed here; however, the factors influencing the distribution of reservoir overpressure remain further to be investigated.

## 5. Discussion

In previous literatures, factors controlling the development of reservoir overpressure generally include undercompaction, hydrocarbon generation, fluid expansion, tectonic movement, clay mineral dehydration, and hydrothermal pressure [39–42]. The clay mineral dehydration and hydrothermal pressure are considered not related with the hydrocarbon generation [43]. Most researchers pay more attention to the influence of undercompaction and hydrocarbon

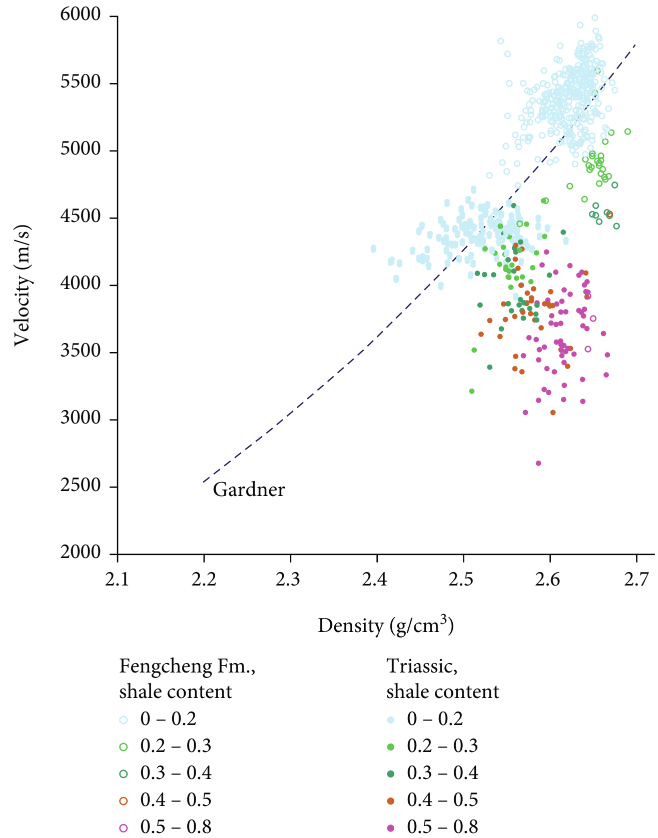


Figure 8: Relationship between density and velocity of the Triassic strata and Fengcheng Formation in the Mahu sag.

generation. In the Mahu sag, we focus on the roles of undercompaction, quartz cementation, hydrocarbon generation and fluid charging, tectonic movement, and caprocks in the formation of reservoir overpressure. Due to the limitation of our study, other factors for overpressure can not be ignored.

*5.1. Undercompaction.* Undercompaction refers to a phenomenon that pore fluid is prevented from flowing out of thick mudstones in time during rapid sedimentation, causing the value of pore pressure to be higher than that of hydrostatic pressure. When sandstones and other reservoirs are interbedded within mudstones, this process can also lead to overpressure in reservoirs. In the Mahu sag, the Karamay-Baijiantan Formation consists of thick mudstones with deep burial depth. Taking Well D11 as an example (Figure 6), the Karamay Formation (3826-4208 m) is dominated by mudstones with 3-8 m thin sandstones interbedded and characterized by rapid changing acoustic curve (AC). The measured pressure coefficients range from 0.9 to 1.4. Only in three intervals (3850-3910 m, 4010-4030 m, and 4100-4120 m) where the layers are dominated by sandstones demonstrated that the pressure coefficients are relatively higher than 1.2, whereas the pressure coefficients of layers dominated by thick mudstones are normal. Besides, the underlying Baikouquan Formation is dominated by conglomerates and sandstones, e.g., Well M18 (Figure 7). In the Baikouquan Formation, the reservoir pressure is 66.7 MPa and the pressure coefficient is 1.74. The overpressure exists in conglomerates and sandstones with particle support structure, showing no material basis of mudstone undercompaction.

Crossplot analysis of density and velocity provides an efficient method to distinguish the effects of undercompaction and fluid charging [44–46]. It is considered that density and velocity of rocks increase with the increasing burial depth. Due to the influence of undercompaction, the density and velocity both show obvious low anomalies in the density and velocity crossplot. However, under the influence of fluid charging, rock density usually remains the same or shows a slight reduction. Here, crossplot analysis of the Triassic strata and Permian Fengcheng Formation is conducted, using logging data from 7 wells in the Mahu sag (Figure 8). It can be found that the density of the Triassic mudstone (purple dots) ranges from 2.60 to 2.66, which is assumed as a normal value of undercompaction in the Mahu sag. However, the acoustic velocity varies from 2500 to 4000 m/s; these data are far away from the Gardner curve and much less than the theoretical value (Figure 8). The high density and low acoustic velocity of the Triassic mudstone indicate that undercompaction has little influence on overpressure, whereas fluid charging may play a vital role in the development of overpressure. Besides, the density of the Fengcheng Formation ranges from 2.55 to 2.70, and the acoustic velocity varies from 3500 to 6000 m/s (Figure 8). These data are mainly around the Gardner curve, suggesting that no effect of undercompaction occurs here.

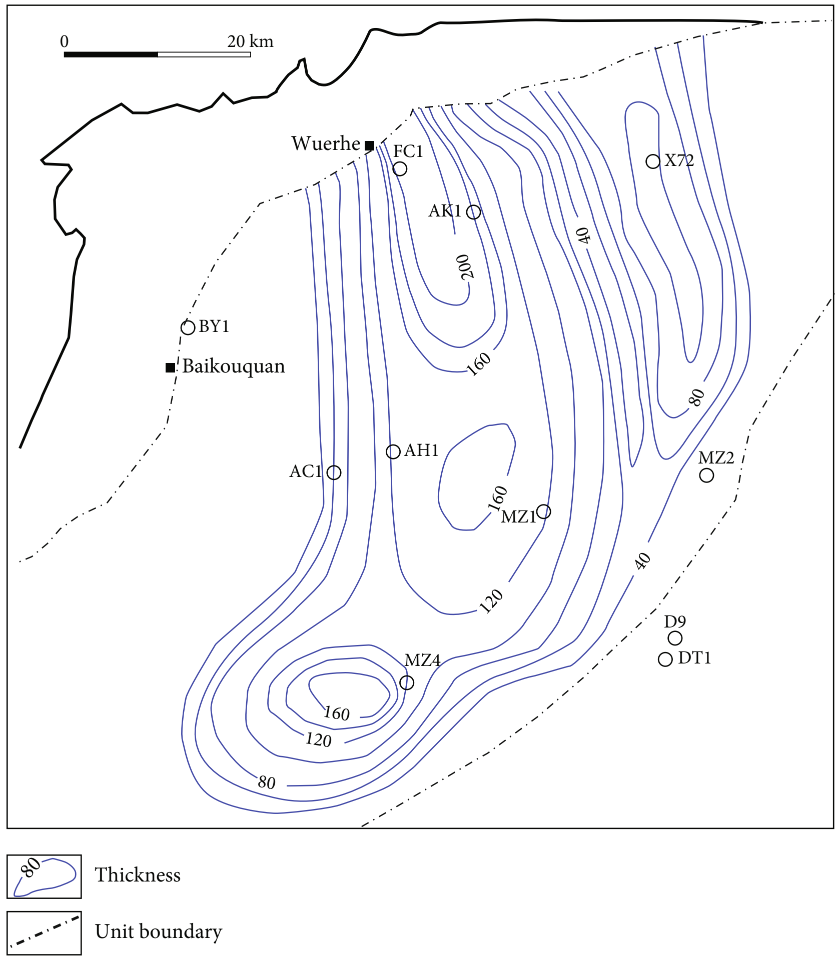


Figure 9: Contour map of the source rocks in the Fengcheng Formation.

*5.2. Quartz Cementation.* Some researchers pay attention to the influence of quartz cementation on reservoir overpressure [47, 48]. It is generally believed that quartz cementation is affected by the burial depth, rich silica sources, temperature, acidic environment, etc. In the Mahu sag, the lithology of the Triassic reservoirs is dominated by sandstone and conglomerates, whose mineral composition is mainly feldspar and rock debris (Figure 7). This indicates that the silica sources are not available enough for quartz cementation in layers below the Triassic. Besides, in the period of early Permian, the northwestern margin of the Junggar basin is considered to be a semideep to deep alkaline lake [49]. This also suggests that the sedimentary environment is not suitable for quartz cementation. In addition, overpressure caused by chemical compaction shows the characteristics that the density increases with the enhancement of overpressure while the velocity does not decrease nor has little decreases [50]. As mentioned above, crossplot analysis of density and velocity also shows that no obvious chemical sedimentation occurs in the Triassic and the Fengcheng Formation (Figure 8).

*5.3. Hydrocarbon Generation and Fluid Charging.* The Fengcheng Formation is the most important source rocks in the Mahu sag. The thickness of source rocks in the Fengcheng Formation increases from the margin of the sag to the center of the sag (Figure 9). Four areas around Wells MZ4, AH1, FC1, and X72 with a maximum thickness of 150 m exist in the sag, which is generally consistent with the distribution of reservoir overpressure (Figure 5). Previous researches have shown that hydrocarbon generation reached a peak in the late Triassic [51]. The distribution of source rocks in the Fengcheng Formation reveals that hydrocarbon generates from the source rock and then charges into the sandstones or conglomerates, causing reservoir overpressure to develop in and around the sag. Further, hydrocarbon flows into its underlying and overlying reservoirs through faults or unconformities and finally results in the formation of reservoir overpressure in the Mahu sag. Fluid charging can be proved by the analyses of oil-source correlation. In the Mahu sag, taking Wells MH1 and JL55 as an example, oil-source correlation analysis shows that the oil and gas in the Triassic, Permian, and upper Carboniferous mainly originate from the Fengcheng source rocks (Figure 10).

*5.4. Faulting and Uplifting by Tectonic Movement.* As mentioned above, fluid charging plays a vital role in developing reservoir overpressure where faults act as conduits transporting hydrocarbon flows. In the Mahu sag, four types of faults, which are developed during multistage tectonic

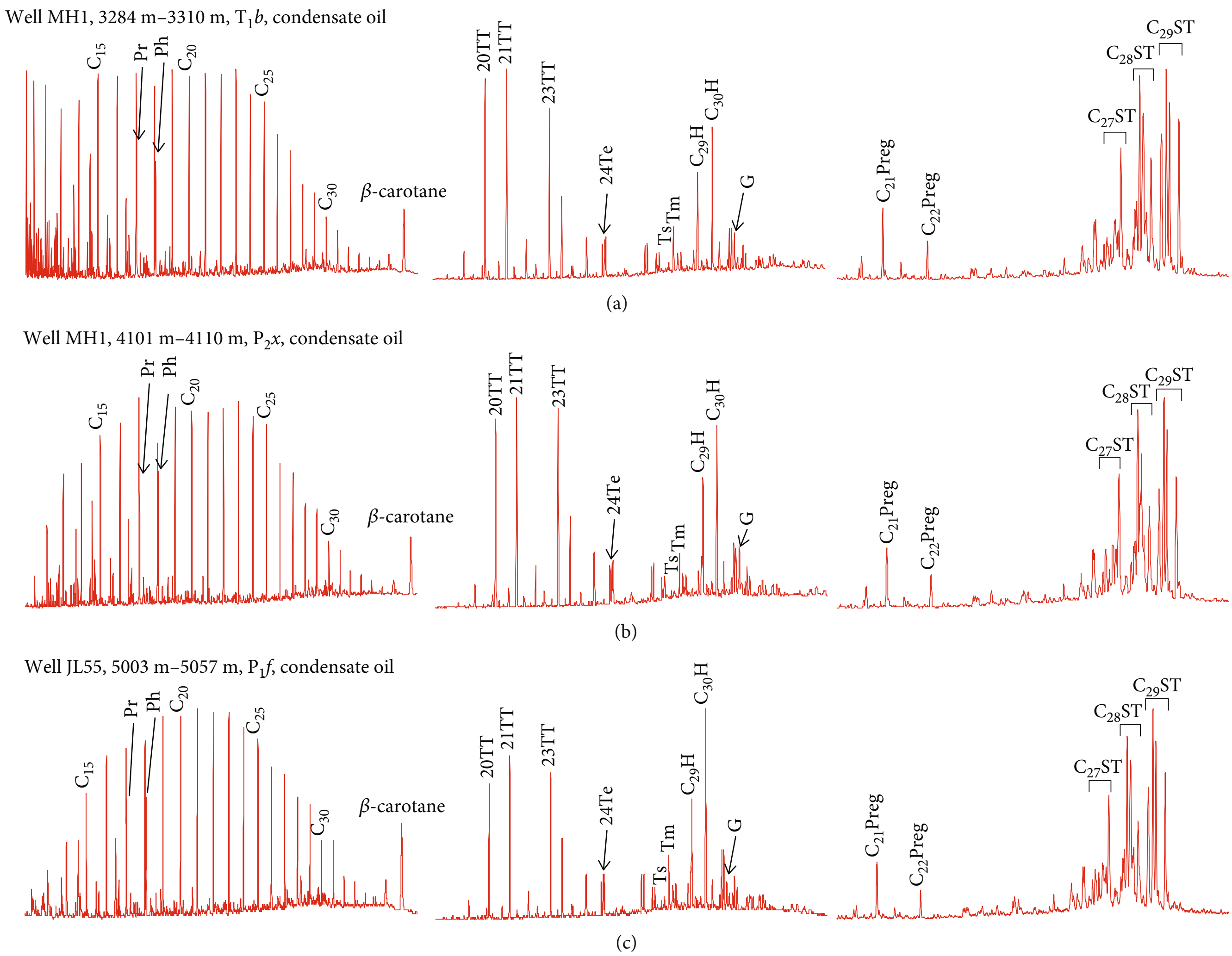


Figure 10: Oil-source correlation analysis of Wells MH1 and JL55 in the Mahu sag.

movements [52], show important influences on the development of reservoir overpressure. To the first, faults develop before the sedimentation of the Jiamuhe Formation, serving as the conduits for oil and gas charging into Carboniferous reservoir from the Fengcheng Formation. The second type of faults develops in early Permian ($P_1j$ and $P_1f$). These faults control the subsidence center of the sag and the distribution of source rocks. To the third, faults were formed during the orogenic movement in the early-middle Permian period. These faults provide efficient pathways for hydrocarbon in the Fengcheng Formation migrating to the Upper Wuerhe Formation and Baikouquan Formation with a distance of 2000-4000 m (Figure 4). This explains the reason why reservoir overpressure exists in the Upper Wuerhe Formation and Baikouquan Formation. To the fourth, faults were formed after Cretaceous, which are mainly micro-strike-slip faults. Since the Baijiantan-Karamay Formation is dominated by mudstones interbedded with sandstones, local reservoir overpressure may develop under the influence of fluid charging through faults (Figure 4).

Besides, uplifting has an important influence on the distribution of formation pressure. When strata in a deep depth are uplifted, if they are overlain by caprocks with good sealing capacity, their pressure would be abnormally higher than the pressure of strata at shallow depth. In the Wuxia-Kebai fault belt and in the northern margin of the Mahu sag, strata below the Upper Wuerhe Formation are greatly uplifted during the orogenic movement (Figures 1(b) and 4). Near the fault belt, the lower-middle Permian sediments are products of alluvial fan facies, dominated by coarse clastic rocks. Under the effect of weak diagenesis, uplifting makes coarse clastic rocks and faults near the fault belt the conduits for hydrocarbon migration. As a result, formation pressure near the fault belt is normal. Taking Well BY1 as an example, which is located at Wuxia-Kebai fault belt, the pressure measurement while drilling shows that the pressure coefficients of Carboniferous and Permian reservoirs range from 1.07-1.10. We can find that formation pressure is normal in the hanging wall or footwall of fault (Figure 4). Besides, it can be found that some wells are characterized with underpressure (<1.0) in layers, especially the Karamay-Baijiantan Formations (Figures 3 and 5). These wells are mainly located at areas in or near the fault belt. This reveals that Wuxia-Kebai fault belt is a region where formation pressure has been released.

*5.5. Role of Caprocks.* Thick mudstones are developed in the upper-middle Triassic strata, overlying on the Upper Wuerhe-Baikouquan Formation ($T_1b$-$P_3w$) in the sag and Carboniferous reservoirs in the Zhongguai uplift. These mudstones are considered the most effective regional caprocks in the sag, which is in consistent with the distribution of reservoir overpressure in the strata below the Triassic in the Mahu sag (Figures 3 and 4). Reservoirs in the Upper Wuerhe-Baikouquan Formation ($T_1b$-$P_3w$) are closely related with the distribution of sediments of fan delta plain facies and alluvial fan facies, where conglomerates with high clay content show a feature of low compressive strength. With the sedimentation and burial of Triassic-Cretaceous deposits, conglomerates in the Upper Wuerhe-Baikouquan Formation are gradually densified, causing their porosities and permeabilities to be lower than the critical value for fluid charging. As a result, the upward and lateral migration of oil and gas in the Upper Wuerhe-Baikouquan Formation is prevented. Besides, as mentioned above, thick mudstones are developed in its overlying Triassic strata. Thus, oil and gas generated from the Fengcheng Formation can migrate through faults and finally charge into reservoirs in the Upper Wuerhe-Baikouquan Formation. The development of caprocks, including the densified conglomerates in the upward and lateral direction and overlying mudstones in the upper-middle Triassic strata, is a necessary condition for the formation of reservoir overpressure in the Mahu sag.

The Fengcheng Formation is dominated by conglomerates near the fault belt and changes into sandstones, dolomitic sandstones, and fine-grained rocks towards the sag, forming a complete sequence from reservoir to source rock. Hydrocarbon generated from the source rock in the sag center migrates into reservoirs in other formations by faults but also migrates into conglomerates and sandstones near the fault belt along the Fengcheng Formation. Similar to the Upper Wuerhe-Baikouquan Formation, as the burial depth increases, conglomerates with high clay content are gradually densified, and thus, the upward migration into conglomerates is prevented. Besides, sandstones and dolomitic sandstones are also densified, but oil and gas generated in the later period can still migrate and accumulate in tight sandstones. The conventional reservoirs with normal pressure and unconventional reservoirs with overpressure orderly accumulate in the Fengcheng Formation in the Mahu sag, where conventional oil reservoirs, tight oil, and shale oil gradually change from the northeast sag margin to the sag center [53].

## 6. Conclusions

Reservoir overpressure is widely developed in the Mahu sag, northwestern Junggar basin. Analysis of measured pressure data of oil reservoirs is conducted in this study. Results show that, in the Baijiantan-Karamay Formation and upper Carboniferous, reservoir overpressure is limited in regional areas. In the Baikouquan-Jiamuhe Formation, reservoir overpressure distributes widely and increases from the margin of the sag to the sag center and generally increases with the increasing altitude. Crossplot analysis of density and velocity shows that undercompaction has little influence on reservoir overpressure here. Analyses of source rock distribution and oil-source correlation reveal that hydrocarbon flows out of the Fengcheng Formation in deep depth and charges into layers at shallow depth, indicating that hydrocarbon generation and fluid charging are responsible for the formation of reservoir overpressure in the Mahu sag. Faulting and uplifting by tectonic movement have an important influence on distribution of reservoir overpressure. The development of densified conglomerates near the fault belt and mudstones in the upper-middle Triassic strata provides a necessary condition for the formation of reservoir overpressure.

## Data Availability

Data can be available by a contact with the first author (whaisheng@petrochina.com.cn).

## Conflicts of Interest

The authors declare no conflict of interest.

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