Fluid Phase Modeling and Evolution of Complex Reservoirs in the Halahatang Depression of the Tabei Uplift, Tarim Basin

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ABSTRACT: The diversity of fluid phases in the oil-gas system and complexity of petroleum genesis bring difficulties to the exploration and development of oil and gas. The phase state and evolution of the complex reservoirs in the Halahatang Depression, Tabei Uplift of the Tarim Basin remains unresolved. In this paper, we simulated the phase characteristic of reservoirs in different blocks and layers including Xinken (O), Ha6 (C), Repu (K), and Yueman (O) distributed from north to south of this area using PVTsim software; rebuilt the burial, temperature, and pressure histories of different blocks and layers by using the PetroMod (1D) software; and recovered the fluid phase evolution process by combined basin modeling, PVT simulation, and fluid inclusion thermal metrics results. The phase modeling results show that the Xinken (O), Ha6 (C), and Yueman (O) reservoirs are confirmed to be oil reservoirs, and the Repu (K) reservoir is in the condensate gas phase currently. The vital time points and temperature and pressure conditions for the three oil reservoirs of Xinken (O), Ha6 (C), and Yueman (O) that transited from the gas–liquid phase to the liquid phase are 356 Ma (57.45 °C, 12.93 MPa), 331 Ma (35.67 °C, 4.03 MPa), and 454 Ma (63.63 °C, 13.27 MPa), respectively. The Ordovician reservoir in the Xinken block underwent three stages of accumulation, which occurred at 400−379 Ma (Devonian), 282−256 Ma (Permian), and 18−16 Ma (Neogene), respectively, and after final accumulation, it remained in a single oil phase state. The Ordovician reservoir in the Yueman block underwent two stages of accumulation in the 294−290 Ma (Permian) and 25−12 Ma (Paleogene–Neogene) and remained in a single oil phase state until now. The Carboniferous reservoir in the Ha6 block was deduced to be charged in the 94−86 Ma (Cretaceous) according to the published authigenic illite K−Ar isotope dating results and still stayed in a single oil phase state unalterably. As for the Cretaceous reservoir in the Repu block, the time point of 11 Ma (98.86 °C, 35.56 MPa) is vital for changing from the gas–liquid coexistence phase state to the condensate gas phase one. In contrast with the Ordovician (ZG7−5) and Cambri for the Tabei Uplift, the oil and condensate gas reservoirs in the Tabei Uplift enjoy a lower pressure range, lower GOR, and a heavier oil density and viscosity. This study provides a quantitative way to rebuild the geologic evolutionary process, phase characteristics, and phase evolution process in complex reservoirs.

1. INTRODUCTION

The Tarim Basin, the largest onshore petrolierous basin in China, is a typical superimposed basin, which is characterized by multiple tectonic movements.1 Adjacent to the hydrocarbon generation center, the Halahatang Depression, located in the center of the Tabei Uplift, has been proved to be a favorable area for hydrocarbon migration and accumulation, and the discovery of the Halahatang large marine oil and gas field reveals its exploration potential.2 However, differences in the maturity stage of source rocks, multiple oil and gas charging, multiple postaccumulation adjustments, transformations, and even destruction have led to the complex phase diversity of fluid and petroleum genesis.3,4 The lithology and pore spaces of the reservoirs also play important roles in fluid flow determination.5−7 Various types of oil and gas including bitumen, super heavy oil, heavy oil, light oil, condensate oil, condensate gas, and wet/dry gas reservoirs have been discovered in the study area.8 The complex diversity of oil and gas phases has brought many difficulties to resource assessment and exploration.9 The phase state of oil and gas reservoirs is controlled by the chemical composition of the fluid and the temperature and pressure conditions.10 The maturity of source rocks and charging of hydrocarbons determine the chemical composition of fluids, and the adjustment and transformation of the oil and gas reservoirs by tectonic movements are accompanied by changes in temperature and pressure conditions. The above two factors make the oil and gas phase probably change during the
evolution process. In this way, knowing the fluid phase evolution under various reservoir conditions (temperature and pressure) in different zones and layers has valuable significance to deepening the understanding of the phase evolution process and distributions of oil and gas in the studied area. Previous studies mainly focused on the regional phase characteristics of current conditions; the phase state evolution of oil and gas variation with reservoir conditions has not been well studied. However, the accumulation process of oil and gas reservoirs has been widely studied, but few studies have been conducted on the phase evolution after oil and gas accumulated. In addition to those, most previous studies only concentrated on a single reservoir, especially the Ordovician reservoirs, and comparative studies on the phase evolution of complex oil and gas reservoirs are also lacking.

Therefore, in this paper, we studied the phase characteristics and evolution process of fluids in different layers of Ordovician (O), Carboniferous (C), and Cretaceous (K) formations from four complex reservoirs including Xinken, Ha6, Repu, and Yueman distributed from north to south in the Halahatang Depression of the Tabei Uplift, Tarim Basin. We simulated the phase characteristic of reservoirs in different blocks and layers using PVTsim software and rebuilt the burial, temperature, pressure histories of different blocks and layers using the PetroMod (1D) software. Then, the fluid phase evolution process was recovered by combining basin modeling, PVT simulation, and fluid inclusion thermal metrics results. For a better understanding of the phase behavior of fluids in complex reservoirs of the studied area, the results of this study were compared with the previous results in the Tazhong Uplift. This study provides a quantitative way to recover the phase evolution process in complex reservoirs, which has shown guiding significance and scientific value for solving the complexity of oil and gas phase states, and also provides applicability and reference for the study of phase evolution in other areas.

2. GEOLOGICAL SETTING
The Tabei Uplift is located in the northern part of the Tarim Basin, which is a long-term inherited developing paleo-uplift (Figure 1b). Its evolution includes five stages: (1) the Pre-Sinian basement and Sinian–Ordovician rift stage during the Caledonian orogeny, (2) the Silurian–Permian uplift and evolution during the Hercynian orogeny, (3) the Triassic–Jurassic foreland basin stage during the Indosinian orogeny, (4) the Cretaceous–Neogene extensional stage during the Yanshanian orogeny, and (5) the Late Neogene–Quaternary rapid subsidence stage during the Himalayan orogeny. The stratigraphy of the Tabei Uplift contains the Sinian–Devonian marine strata, the Carboniferous–Permian marine–terrestrial strata, and the Triassic–Quaternary terrestrial strata. The Halahatang Depression is situated in the center of the Tabei Uplift, with an area of about 4400 km², which is bounded by the Luntai Uplift to the north, the Manjiaer Depression to the south, the Nanka-Yingmali Low Uplift to the west, and the Lunnan Uplift to the east (Figure 1c). The reservoirs in the Halahatang area comprise the Cambrian–Ordovician carbonate reservoirs and the overlying Carboniferous, Triassic, Jurassic, and Cretaceous sandstone reservoirs, and the Ordovician reservoirs are one of the most important reservoirs for petroleum production. In this paper, complex reservoirs containing Ordovician, Carboniferous, and Cretaceous res-
results. The simulated values of the above parameters were tuned to achieve as much consistency as possible with the measured values. The final phase model was determined after calculation and tuning, which can represent the actual fluid in reservoirs. Additionally, the P–T phase diagram can be divided into the liquid phase zone, gas phase zone, condensate gas phase zone, and gas–liquid coexistence phase zone according to the position order of CP, T_pc and T_m. And the identification of fluid phase types depends on where the temperature and pressure conditions fall.

3.2. One-Dimensional (1D) Basin Modeling. 3.2.1. One-Dimensional (1D) Basin Modeling Method. The PetroMod software is a finite-element basin simulator that models the evolution of sedimentary basins.24 In this study, one-dimensional (1D) basin modeling was applied to rebuild the burial, temperature, and pressure histories of the Ha6, Xinken, Repu, and Yueman blocks in the Halahatang Depression using PetroMod 2016 (1D) software by Schlumberger Limited. The basic data required for basin modeling include stratigraphic parameters (age, thickness, and lithology), tectonic events (unconformities, erosion time, and erosion thickness), and boundary conditions (heat flow, paleo-water depth, and sediment-water interface temperature). After building models using the above parameters and calculating, the measured maturity, temperature, and pressure values were used to validate and constrain the modeling results. The burial, temperature, and pressure histories of typical blocks were determined when the modeled and measured results were consistent.

3.2.2. Input Data for One-Dimensional (1D) Basin Modeling. The modeled stratigraphic succession of studied blocks starts from the Quaternary and continues down to the Yingshan Formation (Ordovician). The stratigraphic parameters (age, thickness, and lithology) referred to Zhu et al.25 Huo,26 Zhang,27 and Li.28 The lithology changed from limestone and dolomite to sandstone, mudstone, and clay during the whole geological history. The unconformities occurred in the O2/O3, O/S, S/D, D/C, C/P, P/T, T/J, J/K, and K/E boundaries, and concrete values of erosion thickness and erosion time were collected from Zhang et al.,29 Ni et al.,30 Chang et al.,31 and Deng.32 For the setting of heat flow values, the literature of Wang et al.32 and Ni et al.16 was referenced, and minor adjustments were made for each block. The values of paleo-water depth were estimated based on sedimentary facies type and lithology. The sediment–water interface temperature was calculated automatically by the PetroMod software when the location of each model was determined. The measured maturity temperature and pressure data used for calibration were collected from Ni et al.16 Chang et al.,31 Deng,32 and PVT analysis reports (technical report of the oil company). The strata burial depth of each block is shown in Table 1.

3.3. Fluid Phase Evolution Method. The simulated phase envelope and modeled reservoir temperature and pressure evolution history (labeling as the P-T line) were integrated to study the phase evolution history of fluids in the Xinken, Ha6, Repu, and Yueman blocks. Fluid inclusions contain information about temperature–pressure conditions of petroleum migration in sedimentary basins and the homogenization temperature of fluid inclusions indicates the temperature at which fluids were trapped in reservoirs.13,34 The homogenization temperature of fluid inclusions was collected from published literature.12,13,30-33-37 With the fluid inclusions data, the petroleum accumulation time was determined when contrasting the homogenization temperature and the temperature histories derived from basin modeling. Then, the fluid phase evolution process in the Xinken (O), Ha6 (C), Repu(K), and Yueman (O) reservoirs were discussed by combining the results from basin modeling, PVT simulation, and fluid inclusion thermal metrics.

4. RESULTS

4.1. Fluid Phase Characteristic of Complex Reservoirs. The fluid discovered in the Cretaceous reservoir of Well RP1402 contains the most abundant gaseous hydrocarbons and the least light and heavy hydrocarbons, and the specific contents are N2 + CO2 (6.431%), CH4 (67.123%), C1−5 (85.381%), C6−14 (6.901%), and C14+ (1.287%), respectively (Table 2). On the contrary, the fluid discovered in the Devonian, S = Silurian, O = Ordovician.

### Table 1. Strata Burial Depth Data of the Xinken, Ha6, Repu, and Yueman Blocks

| blocks    | Q   | N   | E   | K   | J   | T   | P   | C   | D   | S   | O   |
|-----------|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|-----|
| Xinken    | 150 | 3500| 3699| 4710| 4803| 5281| 5716| 5786| 6055| 6578| 7451|
| Ha6       | 200 | 3702| 3772| 4873| 4937| 5392| 5630| 5962| 6102| 6485| 7459|
| Repu      | 100 | 3055| 3259| 4264| 4315| 4924| 5373| 5583| 5771| 6329| 7510|
| Yueman    | 50  | 2716| 2961| 3908| 3932| 4583| 5198| 5286| 5423| 6256| 7584|

In the table, Q= Quaternary, N = Neogene, E = Paleogene, K = Cretaceous, J = Jurassic, T = Triassic, P = Permian, C = Carboniferous, D = Devonian, S = Silurian, O = Ordovician.

### Table 2. Fluid Components of the RP1402 (K), Ha6 (C), XK4 (O), and YMW25 (O) Reservoirs

| reservoirs | N2 + CO2 (%) | CH4 (%) | C1−C5 (%) | C6−C14 (%) | C14+ (%) |
|------------|--------------|---------|------------|------------|---------|
| RP1402(K)  | 6.431        | 67.123  | 85.381     | 6.901      | 1.287   |
| Ha6(C)     | 5.728        | 4.716   | 21.697     | 40.488     | 32.085  |
| XK4(O)     | 5.590        | 27.890  | 49.360     | 29.320     | 15.370  |
| YMW25(O)   | 5.366        | 28.244  | 46.320     | 31.607     | 16.706  |

Carboniferous reservoir of Well Ha6 contains the least abundant gaseous hydrocarbons and the highest light and heavy hydrocarbons, and the specific values are N2 + CO2 (5.728%); CH4 (4.716%); C1−5 (21.697%); C6−14 (40.488%); and C14+ (32.085%), respectively. The components of Ordovician fluids discovered in Well XK4 and Well YMW25 are distributed between those of the former two fluid types, which are N2 + CO2 (5.590%); CH4 (27.890%); C1−5 (49.360%); C6−14 (29.320%); and C14+ (15.730%); N2 + CO2 (5.366%); CH4 (28.244%); C1−5 (46.320%); C6−14 (31.607%); and C14+ (16.706%) for Well XK4 and Well YMW25, respectively. Different fluid components determine different shapes of fluid phase diagrams.

The final modeled phase diagrams of the four complex reservoir fluids are shown in Figure 2. Each phase diagram has
its phase zone divided by the positional order of CP, $T_{m}$, and $P_{m}$ on it. It is clear that the phase envelope of the Carboniferous reservoir fluid in Well RP1402 shows an order of CP$-P_{m}-T_{m}$ and enjoys the highest $P_{m}$ and lowest $T_{m}$ because of the highest gaseous hydrocarbon content. The $T_{m}$ and $P_{m}$ are 310.46 °C and 35.16 MPa, and the temperature and pressure of the critical point $(T_{c}, P_{c})$ are 13.59 °C and 29.62 MPa, respectively (Figure 2c). The current reservoir temperature and pressure of the Carboniferous reservoir in the Repu block derived from basin modeling are 118.86 °C and 46.56 MPa, so the fluid in Well RP1402 (K) is classified as the condensate gas phase currently. The phase envelope of the Carboniferous reservoir fluid in Well Ha6 has the lowest $P_{m}$ because of its lowest gaseous hydrocarbon content, and its $T_{c}$, $P_{c}$, $T_{m}$, and $P_{m}$ values are 477.19 °C, 5.20 MPa, 493.12 °C, and 6.99 MPa, respectively (Figure 2b). The modeled current reservoir temperature and pressure of the Carboniferous reservoir in the Ha6 block are 148.47 °C and 67.97 MPa, which confirmed that the fluid in Ha6 (C) is currently in the liquid phase state. The phase envelopes of Ordovician reservoirs in Well XK4 and Well YM25 are displayed between the above two fluid phase envelopes because their gaseous hydrocarbon contents are also distributed between those of the above two types of fluids (Figure 2a,d). The values of $T_{c}$, $P_{c}$, $T_{m}$, and $P_{m}$ in the fluid phase envelopes of Well XK4 and Well YM25 are 445.56 °C, 13.48 MPa, 502.39 °C, and 19.49 MPa and 434.37 °C, 11.90 MPa, 482.95 °C, and 18.14 MPa, respectively. The modeled current reservoir temperature and pressure of the Ordovician reservoirs in the Xinken and Yueman blocks are 165.86 °C and 75.08 MPa and 181.73 °C and 84 MPa, respectively. And they both belong to the liquid phase state currently. The difference between formation pressure and saturation pressure shows the degree of oil reservoir saturation, so it can be judged from the phase diagram that the order of the saturation degree of three oil reservoirs is YM25 < Ha6 < XK4.

4.2. Burial, Temperature, and Pressure Histories of Different Blocks and Layers. The calibration results of vitrinite reflectance (%Ro) of the four blocks are shown in Figure 3. The high matching degree of the simulated and measured results indicates the reliability of the modeled results using the PetroMod software.

The burial history overlaid with the thermal maturity history of the four blocks is shown in Figure 4, which illustrates that the Halahatang Depression has experienced multiple cycles of deposition and erosion. During the Early Caledonian stage, the whole Tabei area experienced a period of unified carbonate platform development, and the Halahatang Depression was a south-dipping slope. Later, in the Middle Caledonian stage, there were two main erosion events that happened after the sedimentation of the Yijianfang Formation (O2) and at the end of the Ordovician (O), causing the unconformities formed in the O2/O3 and O/S boundaries. The deposition of the carbonate platform ended, and the sedimentary facies turned to the mixed shelf facies in this period. During the Late Caledonian stage, the study area underwent two strong uplift and erosion events that occurred at the end of Silurian and Devonian, and the sedimentary facies of this period were littoral, tidal-flat, and delta plain facies. During the Late Hercynian stage, massive magma erupted and the Halahatang Depression experienced a continuous uplift, with the marine sedimentation ending at the end of the Permian. Then, during the Indosinian—Yanshanian orogeny, the overall tectonic activity intensity in the Halahatang Depression was relatively weaker than the previous orogeny. Since the Himalayan period, the Halahatang Depression subsided rapidly, accompanied by a sedimentation thickness of about 2600–3500 m. The morphology of the Mesozoic—Cenozoic strata changed to north-dipping, and the present tectonic framework of the Halahatang Depression was finalized in this period. The burial depth of the strata reached
the maximum of the current, and the modeled burial depth of the Yingshan Formation (O1−2) exceeds 7400 m.

Figure 4 also reflects the maturity evolution history of these four blocks. Overall, four blocks reached the low mature stage (>0.5% Ro) in the Silurian and quickly reached the mature stage (>0.8% Ro) in the Permian because of the thermal event. After that, the Yueman block first reached the high maturity stage (>1.2% Ro) in the Jurassic, and then the other three blocks reached the high maturity stage in the Neogene. In summary, for the studied blocks in this paper, their current burial depth of the Ordovician strata increases from north to south, and the current burial depth of the Mesozoic−Cenozoic strata decreases from north to south in general because of the changing of the dip direction. The erosion intensity also decreases from north to south, and maturity increases from north to south.

The differences between the burial history and maturity evolution history of studied reservoirs (O/C/K) in the four blocks are shown in profiles of Figure 5. Although the Xinken and Yueman blocks both are Ordovician reservoirs, their maximum burial depth difference in history exceeds 1000 m, and the current difference is about 600 m. The current buried depth of the Carboniferous reservoir in the Ha6 block is about 5900 m, and that of the Cretaceous reservoir in the Repu block exceeds 4000 m. Different burial histories largely determine their different maturity histories. The maturity of the Ordovician reservoir in the Yueman block reached the low mature stage (>0.5% Ro) in the Silurian and reached the mature stage (>0.8% Ro) in the Permian. The current value of maturity is about 1.8% Ro. The maturity of the Ordovician reservoir in the Xinken block reached the low mature stage (>0.5% Ro) in the Permian and reached the mature stage (>0.8% Ro) in the Neogene. The current maturity value is about 1.3% Ro. The maturity of the Carboniferous reservoir in the Ha6 block reached the low mature stage (>0.5% Ro) in the Permian and remained in the mature stage until now with a current maturity value of about 1.1% Ro. As for the maturity of the Cretaceous reservoir in the Repu block, it reached the low mature stage (>0.5% Ro) in the Neogene and stayed in the low mature stage to the present.
The temperature and pressure evolution histories of studied reservoirs in the four blocks are shown in Figure 6. The temperature history is closely related to the evolution of heat flow, burial depth, and sediment–water interface temperature. The Tarim Basin is a typical "cool" basin, and its heat flow represents an overall decreasing trend from the Ordovician to the present except for the massive magma eruption in the Permian. The pressure history is significantly linked with the burial depth and lithology. It can be seen from Figure 6 that the temperature and pressure of all reservoirs show an overall increasing trend with the increasing of burial depth except for the decreasing trend in some periods caused by the uplift and erosion events. For studied reservoirs in the four blocks, the sequence of reservoir temperature and pressure from high to low is Yueman (O), Xinken (O), Ha6 (C), and Repu (K) due to the decreasing burial depth. The current temperatures of the Yueman (O), Xinken (O), Ha6 (C), and Repu (K) reservoirs are 181.73 °C, 165.86 °C, 148.47 °C, and 118.86 °C, and the current pressures of these four reservoirs are 84, 75.08, 67.97, and 46.56 MPa, respectively.

4.3. Evolution Characteristics of Fluid Phases and Physical Properties (Density, Viscosity). The simulated phase envelope and modeled reservoir temperature and pressure evolution history (labeling as the $P$--$T$ line) were superimposed together to study the phase evolution characteristics of fluids in the Xinken (O), Ha6 (C), Repu (K), and Yueman (O) reservoirs (Figure 7). The starting time of the reservoir temperature and pressure evolution history in the figure is the time when the strata began to deposit.

For the Ordovician reservoir in the Xinken block, its initial formation temperature and pressure are 24.37 °C and 0.16 MPa. It is shown in Figure 7a that the reservoir P–T line is originally in the gas–liquid coexistence phase zone and then first changes to the liquid phase zone at the point of 62.73 °C and 13.27 MPa, which corresponds to 407 Ma (Devonian) and keeps in the liquid phase for a short time. Then it turns back to the gas–liquid coexistence phase state and finally keeps in the liquid phase state after 356 Ma (Carboniferous). It reveals that the conditions of 57.45 °C and 12.93 MPa and the time point of 356 Ma (Carboniferous) are vital for the Ordovician reservoir in the Xinken block staying in the liquid phase. For the studied Carboniferous reservoir in the Ha6 block, its initial formation temperature and pressure are 23.1 °C and 0.31 MPa. The P–T line goes across the gas–liquid coexistence phase zone to the liquid phase zone in the early stage (Figure 7b). The cross point of the two lines is 35.67 °C and 4.03 MPa, and the time point that corresponds to it is 331 Ma (Carboniferous). It represents that the temperature and pressure of 35.67 °C and 4.03 MPa (331 Ma) are vital conditions for the current Carboniferous reservoir fluid phase changing from the
gas–liquid coexistence phase state to the liquid phase state. For the studied Cretaceous reservoir in the Repu block, its initial formation temperature and pressure are 23.24 °C and 0.10 MPa. In Figure 7c, it is clear that the reservoir P–T line stays in the gas–liquid coexistence phase zone for a long time. Then, it reaches the condensate gas phase zone after the point of 98.76 °C and 33.87 MPa, corresponding to 11 Ma (Neogene). It represents that the temperature and pressure of 98.76 °C and 33.87 MPa are important conditions for the current Cretaceous reservoir fluid phase changing from the gas–liquid coexistence phase to the condensate gas phase. The initial formation temperature and pressure of the studied Ordovician reservoir in the Yueman block are 23.48 °C and 0.52 MPa. Its fluid phase evolution characteristic is similar to that of Well XK4. It is shown in Figure 7d that the reservoir P–T line is in the gas–liquid coexistence phase zone in the early stage, and it changes into the liquid phase zone after the point of 63.63 °C and 13.27 MPa, which corresponds to 454 Ma (Ordovician). This indicates that the temperature and pressure of 63.63 °C and 13.27 MPa (454 Ma) are significant conditions for the Ordovician reservoir fluid phase changing from the gas–liquid coexistence phase to the liquid phase in the Yueman block.

Besides the evolution characteristics of fluid phases in the Xinken (O), Ha6 (C), Repu (K), and Yueman (O) reservoirs, their evolution characteristics of physical properties (density, viscosity) were also calculated (Figure 8). Both the liquid density and viscosity show overall decreasing trends during the whole geological evolution history, while that of the gas phase shows opposite trends. As for the density, it is clear that the liquid density of the Ha6(C) reservoir fluid is the heaviest among these four blocks, and its fluctuation is the smallest with values mainly stable at 0.76 g/cm³ (Figure 8b). The second heaviest of the four fluids is the Xinken (O) reservoir fluid, which is mainly concentrated in 0.73 g/cm³ during the whole evolution history (Figure 8a). And the liquid density of the Yueman (O) reservoir fluid is about 0.70 g/cm³, which is the third heaviest one (Figure 8d). The density of the condensate gas fluid in the Repu (K) reservoir fluctuates with the most scale, whether in the liquid or gas phase, and values of the two phases vary within the range of 0.74–0.50 and 0–0.40 g/cm³, respectively (Figure 8c). For the viscosity, its fluctuation is greater than the density. The liquid viscosity of the Xinken (O) reservoir fluid fluctuates with the most scale, which significantly reduces before the phase transition point, and its values mainly focus on 0.60 cP after 407 Ma (Figure 8e). The viscosity of the Yueman (O) reservoir fluid also fluctuates greatly, and the values of liquid phase change among 2.20–0.66 cP and 0.63–0.45 cP before and after the phase turning point (454 Ma; Figure 8h). Compared with the above two oil reservoirs, the liquid viscosity of the Ha6 (C) reservoir fluid shows less fluctuation throughout the whole evolution process, and the range of values during the whole process is 2.80–1.38 cP (Figure 8f). For the condensate gas fluid in the Repu (K) reservoir, the liquid viscosity shows relatively small fluctuations, while that of the gas viscosity shows relatively large fluctuations, and their values are ranging 1.22–0.10 cP and 0.01–0.06 cP, respectively (Figure 8g).

5. DISCUSSION

5.1. The Fluid Phases Evolution Process Combining with Regional Accumulation History. Using fluid
inclusions to judge the accumulation stages has been widely employed in the Tabei Uplift. In this paper, we investigate the fluid phase evolution process of studied blocks by combining the published fluid inclusions data, authigenic illite K—Ar isotope dating results, and the phase simulation results above. According to the previous studies8,17, there are three main accumulation stages in the Tabei Uplift: First, the Cambrian—Lower Ordovician source rocks generated a large amount of liquid hydrocarbon and charged into traps during the Middle—Late Caledonian stage. Then, the second oil charge occurred in the Late Hercynian stage. Finally, the oil accumulated in early stages began to crack, and oil cracking gas charged into traps in the Himalayan stage. Among all accumulation stages, the charging in the Late Hercynian is the most important and effective one to the entire Halahatang Depression, and the majority of oil and gas reservoirs today still maintained the state when the reservoir was formed in the Late Hercynian25.

For the Ordovician reservoir in the Xinken block, the above result (Figure 7a) indicates the following possible accumulation process: if the oil and gas charged and accumulated before 356 Ma (Carboniferous), it would undergo multiple phase changing processes between the gas—liquid coexistence phase and liquid phase after accumulation. If the oil and gas charged and accumulated after 356 Ma (Carboniferous), it would stay in the liquid phase unalterably. The previous studies have verified that fluid inclusions in the Ordovician oil reservoir of the Xinken block can be divided into three stages, and homogeneous temperatures of these three stages are in the ranges 65—90 °C, 100—110 °C, and 120—130 °C, respectively30,35,36. The inclusions of the first two stages are mainly oil inclusions, and those of the third stage are mainly composed of gas inclusions. The accumulation time obtained by matching the ranges of homogeneous temperatures with the modeled reservoir temperature history is 400—379 Ma (Devonian), 282—256 Ma (Permian), and 18—16 Ma (Neogene), respectively (Figure 9a). Combining this result with Figure 7a, it is clear that the reservoir fluid has undergone three stages of charging, and it remained in the liquid phase after finally being charged in 18—16 Ma (Neogene). It also confirms that the third stage of gas invasion had little impact on the reservoir fluid, which did not change the fluid type significantly. For the studied Ordovician reservoir in the Yueman block, it can be judged by the previous result (Figure 7d) that if the oil and gas charged and accumulated before 454 Ma (Ordovician), the reservoir would turn from the gas—liquid coexistence phase to the liquid phase after 454 Ma (Ordovician); if the oil and gas charged and accumulated after 454 Ma (Ordovician), then the fluid would keep in the liquid phase unalterably. The previous study has verified that fluid inclusions in the Ordovician oil reservoir of the Yueman block can be divided into two stages, and the homogeneous temperatures ranges of these two stages are 110—120 °C and 150—170 °C16. In contrast with the reservoir temperature history plotted in Figure 5d, these two sets of homogeneous temperatures correspond to an accumulation time of 294—290 Ma (Permian) and 25—12 Ma (Paleogene—Neogene; Figure 9b). Combined with Figure 7d, it can be inferred that the fluid has undergone two stages of charging and remained in the liquid phase unalterably after the second charge in 25—12 Ma (Paleogene—Neogene).

For the studied Carboniferous reservoir in the Ha6 block, the result of fluid phase evolution characteristics (Figure 7b) shows that if the oil and gas charged and accumulated before 331 Ma (Carboniferous), the reservoir would turn from the gas—liquid coexistence phase to the liquid phase after 331 Ma...
(Carboniferous); if the oil and gas charged and accumulated after 331 Ma (Carboniferous), then the fluid would stay in the liquid phase until now. The Carboniferous reservoir fluid in the Ha6 block was deduced to be charged in the 94–86 Ma (Cretaceous) according to the authigenic illite K–Ar isotope dating results, and the charging temperature and pressure were inferred to be 84–88 °C and 25–28 MPa. Combining this result with Figure 7b, it can be concluded that the fluid in the Carboniferous reservoir of the Ha6 block remained in the liquid phase unalterably after being charged in the 94–86 Ma (Cretaceous). For the studied Cretaceous reservoir in the Repu block, the above result (Figure 7c) indicates that if the petroleum charged and accumulated before 11 Ma (Neogene), the reservoir would turn from the gas–liquid coexistence phase to the condensate gas phase after 11 Ma (Neogene); if the petroleum charged and accumulated after 11 Ma (Neogene), the fluid would stay in the condensate gas phase until now. However, the accumulation time of the Cretaceous condensate gas reservoir in the Repu block lacks fluid inclusion evidence.

5.2. Accumulation Conditions of the Oil and Gas Reservoirs in the Halahatang Depression. The Halahatang Depression is close to the Manjaer Depression, which is a vital hydrocarbon generation center in the Tarim Basin. The main effective source rock of the Cambrian Yuertusi Formation provided sufficient hydrocarbons, and hydrocarbons mainly generated and accumulated in the Late Caledonian, Late Hercynian, and Late Himalayan stages. The large-size strike-slip faults developed in the Early–Middle Caledonian, small-size strike-slip faults developed in the Late Caledonian–Early Hercynian, and volcanic faults in the Late Hercynian and other faults play important roles in the petroleum accumulation of the Halahatang area, especially the first one. The Ordovician reservoirs were deposited in open platform facies, and the karst fracture-vug reservoir was developed in the Yingshan Formation and Yijianfang Formation, composed of micrite limestone and grain limestone. The reservoir in the Carboniferous is the breccia section of the Bachu Formation, which was deposited in the tidal flat–delta plain facies and was mainly composed of sandstone, siltstone, sandy conglomerate, and mudstone. The Cretaceous reservoir was deposited in the river-delta facies and the main lithology is sandstone, siltstone, glutenite, and mudstone. The high porosity and permeability of the reservoir also provided a good reservoir space and migration pathway for hydrocarbon fluid, and the reservoir property is becoming better close to the faults. For the three oil reservoirs, Ha6 (C), Xinken (O), and Yueman (O), the thickness of overlying cap rocks is 268 m (Ha6), 306 m (Xinken), and 639 m (Yueman), respectively. The current oil densities of the Ha6 (C), Xinken (O), and Yueman (O) reservoirs are 0.77 g/cm³, 0.74 g/cm³, and 0.71 g/cm³, respectively.

5.3. The Contrast with Oil and Gas Reservoirs in the Tazhong Uplift. In the Tarim Basin, the oil and gas reservoirs were mainly discovered in the Tazhong and Tabei Uplift. To clarify the phase characteristics and differences between the Tazhong and Tabei Uplift, we discussed phase characteristics of the studied typical reservoirs in the Tabei Uplift and differences of typical Ordovician, ZG7–5 (O), and Cambrian reservoirs, ZS1 (C) and ZS5 (C), in the Tazhong Uplift by combining our results with the previous works. The phase diagram containing all reservoirs is displayed in Figure 10, and concrete data are listed in Table 3. The phase envelope of the oil and condensate gas reservoirs in the Tazhong Uplift both have a higher pressure range than the same type of studied reservoirs in the Tabei Uplift (Figure 10). As for the condensate gas reservoirs, the phase envelope of the fluid in Well ZG7–5, Tazhong Uplift, has the higher cricondenbar because of the highest methane content (83.083%), while that of the Cretaceous condensate gas reservoir in Well RP1402, Tabei Uplift has the lower cricondenbar because of the lower methane content (67.123%). The critical point of the condensate gas reservoir in the Tazhong Uplift has lower critical temperatures than that of the Tabei Uplift. And the condensate content in the Tazhong reservoir is also lower than that in the Tabei Uplift, which is 628.292 and 645.713 g/m³, respectively. As for oil reservoirs, the phase envelopes of the Cambrian light oil reservoirs in Well ZS5 and ZS1, Tazhong Uplift, are close to each other, whose contents of methane are 34.443% and 48.653%, and they enjoy a higher pressure range and higher critical temperatures than that of the oil reservoirs in the Tabei Uplift. Their production gas–oil ratios (GORs) are in the range of 108–435 m³/m³ and 435–563 m³/m³, respectively. In addition, the reservoir density and viscosity of Cambrian oils are very light, which are 0.64 g/cm³ and 0.18 cP (ZS5) and 0.56 g/cm³ and 0.12 cP (ZS1), respectively. On the contrary, the phase envelopes of studied oil reservoirs in the Tabei Uplift (Well YM25, XK4, and Ha6) show lower cricondenbar and higher critical temperatures. Their production gas–oil ratios (GORs) are also lower than that of the Cambrian oil reservoirs in the Tazhong Uplift, and the specific values are less than 100 m³/m³. The oil density and viscosity are heavier than that of the Cambrian oil reservoirs in the Tazhong Uplift.

6. CONCLUSION

The fluid phase modeling and evolution of complex reservoirs in the Halahatang Depression of the Tabei Uplift, Tarim Basin were studied in this paper. The studied blocks, Xinken, Ha6, Repu, and Yueman blocks in the Halahatang Depression, the Tabei Uplift, are distributed from north to south, respectively. The overall erosion intensity decreases from north to south while the maturity increases from north to south. Meanwhile, the sequence of modeled reservoir temperature and pressure from high to low is Yueman (O), Xinken (O), Ha6 (C), and Repu (K) blocks due to the decrease of the reservoir burial depth.

The phase envelopes of the fluids in the XK4 (O), Ha6 (C), and YM25 (O) reservoirs show an order of $P_m$–CP–$T_m$ and have a higher cricondenbar than that of the RP1402 (K) reservoir, which were all confirmed to be the liquid phase currently. The order of the saturation degree of three oil
reservoirs (XK4, Ha6, and YM25) is YM25 < Ha6 < XK4. The Repu (K) reservoir fluid was confirmed to be the condensate gas phase currently, and its phase envelope has the highest cricondenbar, with an order of $\text{CP} - P_{m} - T_{m}$. When the results of phase modeling and basin modeling were integrated, the key time point and temperature and pressure conditions of phase changing were verified for all reservoirs. For the three oil reservoirs in Xinken, Ha6, and Yueman blocks, the critical time points and temperature and pressure conditions for their transition from the gas–liquid phase to liquid phase are 356 Ma (57.45 °C, 12.93 MPa), 331 Ma (35.67 °C, 4.03 MPa), and 454 Ma (63.63 °C, 13.27 MPa), respectively. For the Cretaceous reservoir in the Repu block, the time point of 11 Ma (98.86 °C, 35.56 MPa) is vital for changing from the gas–liquid coexistence phase to the condensate gas phase.

The phase evolution characteristic integrated with fluid inclusion and authigenic illite K–Ar isotope dating results shows all of the evolution stages as follows. The Ordovician reservoir in the Xinken block underwent three stages of accumulation, which occurred in the 400−379 Ma (Devonian), 282−256 Ma (Permian), and 18−16 Ma (Neogene), respectively, and remained in the oil phase after being accumulated. The Carboniferous reservoir in the Ha6 block was deduced to be charged in the 94−86 Ma (Cretaceous) and stayed in the oil phase unalterably. The Ordovician reservoir in the Yueman block underwent two stages of accumulation in the 294−290 Ma (Permian) and 25−12 Ma (Paleogene−Neogene) and remained in the oil phase until now. For these three oil reservoirs, the current density of oils in the reservoirs is estimated as 0.77 g/cm³ (Ha6), 0.74 g/cm³ (Xinken), and 0.71 g/cm³ (Yueman), respectively.

Contrasted with the Ordovician (ZG7−S) and Cambrian reservoirs (ZS1, ZS5) in the Tazhong Uplift, it is found that both oil and condensate gas reservoirs in the Tabei Uplift have a lower pressure range, lower GOR, and heavier oil density and viscosity than the same type of studied reservoirs in the Tazhong Uplift because of the lower gas content compared with reservoirs in the Tazhong Uplift.

This study presents a quantitative way to recover the phase evolution process in complex reservoirs, which provides guiding significance and scientific value for solving the complexity of the oil and gas phase state. This study also exhibits applicability and reference for the study of phase evolution in other areas. After rebuilding the burial, temperature, and pressure histories and recovering fluid phase models, the phase evolution history can be studied by combining basin modeling, PVT simulation, and fluid inclusion thermal metrics results.

Table 3. Comparison of Typical Oil and Gas Reservoirs in the Tazhong and Tabei Uplift

| reservoirs | types   | N$_2$ + CO$_2$ + H$_2$)$_s$ | C$_2$−C$_4$ | C$_4$−C$_{14}$ | C$_{14}$+ | production GOR (m$^3$/cm$^3$) | in situ oil density (g/cm$^3$) | in situ oil viscosity (mPa·s) |
|------------|---------|----------------------------|-------------|---------------|---------|-------------------------------|-------------------------------|-------------------------------|
| ZG7−S(O)   | condensate gas | 7.307 | 84.253 | 7.092 | 1.350 | 822.7 | 0.64 | 0.18 |
| RPI402(K)  | condensate gas | 6.431 | 85.381 | 6.901 | 1.287 |
| ZS5(G)     | light oil     | 13.658 | 53.012 | 27.567 | 5.766 | 108−435 | 80.3 | 0.12 |
| ZS1(G)     | light oil     | 18.453 | 64.530 | 13.413 | 3.602 | 435−563 | 60 | 0.74 |
| YM25(O)    | light oil     | 5.366 | 46.320 | 31.607 | 16.706 | 80.3 | 0.71 | 0.57 |
| XK4(O)     | light oil     | 5.590 | 49.360 | 29.320 | 15.730 |
| Ha6(C)     | light oil     | 5.728 | 21.697 | 40.488 | 32.085 | 32$^a$ | 0.77 | 1.55 |

$^a$Single degassing gas–oil ratio at reservoir temperature.

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Notes

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