

Original Paper

Fluid inclusion analysis and carbonate U–Pb dating reveal shale oil accumulation processes in the Qingshankou Formation, Songliao Basin, NE China



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ABSTRACT

Direct constraints on the absolute timing of shale oil accumulation and microscale migration within shale systems remain limited. Here we investigate ostracod limestone interbeds, calcite veins, and barite veins from the Qingshankou Formation in the Songliao Basin, integrating fluid inclusion petrography, diagenetic phase analysis of host minerals, and in situ U–Pb dating to reconstruct the timing and evolution of shale oil accumulation in Member 1 of the Qingshankou Formation. Hydrocarbon inclusions within the veins are dominated by yellow-green, blue-white, and predominantly blue fluorescence assemblages. Blue-fluorescing inclusions are characterized by fluorescence $\lambda_{\max}$ below 485 nm and CIE chromaticity coordinates (X, Y) lower than 0.3, indicating a relatively high level of thermal maturity. Homogenization temperatures of hydrocarbon inclusions and their coexisting aqueous inclusions show good correspondence with the diagenetic stages of host minerals, reflecting multiple episodes of fluid trapping. Trapping ages of hydrocarbon inclusions inferred from burial–thermal history reconstruction are broadly consistent with in situ U–Pb ages of calcite veins (65.3 ± 4.8 Ma and 58.2 ± 5.2 Ma), indicating that vein formation and hydrocarbon-bearing fluid activity were essentially synchronous at the study area scale. Image-based analysis of the hydrocarbon inclusion abundance index (IHI-AI) shows that blue-fluorescing inclusions are relatively enriched in the central Gulong Sag, and their spatial distribution closely matches the occurrence of high-maturity, light shale oil. Integrated interpretation of fluorescence spectral parameters, equivalent hydrocarbon inclusion reflectance derived from the image-based fluorescence CIE chromaticity (IF–CIE) method (EqHIR₀), homogenization temperature data, diagenetic evolution, and in situ U–Pb dating indicates that, after the Qingshankou Formation reached a high level of thermal maturity near the end of the Cretaceous, shale oil retained within the source rock continued to undergo intrasource microscale migration and redistribution from the middle to late Paleogene through the Neogene. Distinct fluorescence–chromaticity signatures of hydrocarbon inclusions indicate that shale oil accumulation was closely associated with continuous hydrocarbon generation and sustained intrasource micromigration. This study provides an integrated framework for constraining the timing and evolutionary pathways of shale oil accumulation in lacustrine shale systems.

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1. Introduction

Shale oil has become a major resource as the development of unconventional petroleum systems has advanced. The Qingshankou Formation in the Songliao Basin represents one of the most important targets for lacustrine shale oil exploration in China, characterized by widespread source rocks and high resource potential (Sun, 2020; He et al., 2022c). Its petroleum system is commonly described as self-sourced and self-stored, with hydrocarbons generated and retained within the same stratigraphic interval (Meng et al., 2022; Bai et al., 2024; Feng et al., 2025). Previous studies have established a solid understanding of its depositional environment, organic matter enrichment mechanisms, lithofacies architecture and reservoir space (Feng et al., 2021; Zhang et al., 2021; Fu et al., 2022; Liu et al., 2021, 2024). Micro- to nanoscale pores associated with organic matter, clay-organic aggregates and bedding-parallel microfractures are widespread and provide storage and mobility space for shale oil (Wang et al., 2023, 2024; Sun et al., 2023; He et al., 2024c; Niu et al., 2025; Liu et al., 2025). Observations from cryogenic confocal microscopy, scanning electron microscopy and nuclear magnetic resonance further show that light oil is preferentially hosted in micropores and clay intercrystalline pores and exhibits pronounced spatial heterogeneity (Zhang et al., 2021; Li et al., 2022; Lin et al., 2024; Shao et al., 2026). Despite these advances, most existing studies emphasize static reservoir properties and microstructural characteristics, whereas the temporal evolution of shale oil accumulation and migration remains poorly constrained. Direct chronological constraints on when shale oil was generated, migrated and redistributed within the source rock are still lacking (Sun et al., 2021; He et al., 2023a).

In recent years, the combined application of fluid inclusion analysis and in situ U–Pb dating has provided new opportunities to constrain the timing of petroleum system evolution (Holdsworth et al., 2019; Chen et al., 2021; Zhang et al., 2022; Cong et al., 2022; Su et al., 2022b; Sun et al., 2023; Yang et al., 2025). Petroleum inclusions record the physicochemical conditions of hydrocarbon charging events through their fluorescence properties, homogenization temperatures and compositions, while U–Pb dating of host minerals provides an absolute temporal framework (Shen et al., 2021; Cheng and Xiao, 2023; Ge et al., 2023). This integrated approach has been widely applied to decipher complex, multi-stage petroleum histories in carbonate and shale systems (Su et al., 2022a; Gui et al., 2023; Deng et al., 2023; Du et al., 2023; Cong et al., 2024; Wang et al., 2024; Zhu et al., 2024). Calcite veins containing petroleum and aqueous inclusions have proven particularly useful for identifying hydrocarbon charging and thermal evolution (Amthor et al., 2015; Ge et al., 2023; Song et al., 2023). Bedding-parallel calcite veins are closely linked to fluid overpressure, stress regimes and hydrocarbon generation–migration processes (Sun et al., 2023), and their petroleum inclusions indicate that vein formation and hydrocarbon movement are temporally coupled (Mangenot et al., 2024). In addition, ostracod shell fragments within carbonate interbeds contain multiple pore types that may serve as localized pathways and storage sites for hydrocarbons (Ji et al., 2024). Recent studies further show that calcite veins, hydrothermal minerals and ostracod limestone interbeds are widespread in the Qingshankou Formation and likely record fluid activity associated with shale oil accumulation (Qiao and Hu, 2014; He et al., 2022a, 2023b, 2024a, 2024b, Wu et al., 2024). Therefore, it is necessary to integrate the above approaches for reconstructing paleo-reservoir accumulation history in the study area by establishing a fluid inclusion-centered

integrated framework, thereby providing key evidence for constraining the timing of shale oil accumulation.

In this study, we establish a multi-parameter temporal framework integrating fluid inclusion thermal parameters, CIE chromaticity-based maturity indices, host-mineral paragenesis, in situ U–Pb ages, and burial–thermal history reconstruction, here termed the FI–CIE–U–Pb–Burial integrated inversion approach, to constrain the timing and sequence of shale oil retention, micro-migration, and redistribution in the Qijia–Gulong Sag, Songliao Basin. To this end, we investigate calcite veins, barite veins, and ostracod limestone interbeds from 16 samples collected from four wells in this key shale oil exploration area of the basin. Based on this integrated approach, we clarify the temporal relationships among fluid activity, vein formation, and shale oil accumulation. The results provide new insight into the dynamic evolution of this lacustrine shale oil system.

2. Geological setting

The Qijia–Gulong Sag is located in the northern part of the Central Depression of the Songliao Basin, northeastern China (Fig. 1(a) and (b)). The Gulong shale of the Qingshankou Formation is the primary shale-oil target in this area, with estimated resources of approximately 1.27×10^9 tons (Cui et al., 2022; He et al., 2022b). The sag represents a long-lived, inherited deep-lacustrine depocenter (Wang et al., 2009). During deposition of the Qingshankou Formation, the basin was in its main subsidence stage, characterized by rapid but relatively stable tectonic subsidence punctuated by minor episodic fluctuations (Chen et al., 2016). Sediment accumulation broadly kept pace with accommodation creation, resulting to a predominantly compensational sedimentary regime, with semi-deep to deep lacustrine facies dominating the depositional environment (Liu et al., 2019; Feng et al., 2021; Zeng et al., 2021; Zhou et al., 2023). The Gulong shale is mainly developed in Member 1 (K_2qn^1) and the lower part of Member 2 (K_2qn^2) of the Qingshankou Formation and is subdivided into nine sublayers (Q1–Q9) (Li et al., 2018). It consists predominantly of mudstone and shale, with thin interbeds of siltstone and carbonate. Microfractures and veins with different attitudes are common, and numerous small-scale faults occur near the base of the formation (Fig. 1(b)) (Shao et al., 2019), serving as important recorders of hydrocarbon migration and fluid activity (Wang et al., 2017; Jia et al., 2021; He, 2022; Ji et al., 2024).

Since deposition of the Qingshankou Formation, five main tectonic stages have been recognized (Wang et al., 2018; Liu et al., 2023). (1) During the early thermal subsidence and transtensional stage, the Qingshankou Formation was rapidly buried to depths of approximately 0.4–0.7 km. (2) An initial phase of differential uplift and compression-torsion reversal during Yaojia Formation deposition led to basin shrinkage and local hiatus or erosion (Wei et al., 2010). (3) Continued differential subsidence during Nenjiang Formation deposition resulted in renewed deepening of the basin, with burial depths of the Qingshankou Formation reaching 1.6–2.0 km (Chen and Chen, 1996). (4) Basin contraction and folding associated with the Yanshanian IV–V tectonic phases caused regional uplift and partial erosion during late Nenjiang to Sifangtai and Mingshui deposition, although the Qingshankou Formation continued to be buried intermittently and reached depths of 2.2–2.6 km by the end of Mingshui time. (5) Finally, early Himalayan tectonism led to regional tectonic uplift from the late Mingshui to early Yian stages, affecting the Qingshankou Formation to varying degrees (Fu et al., 2025).

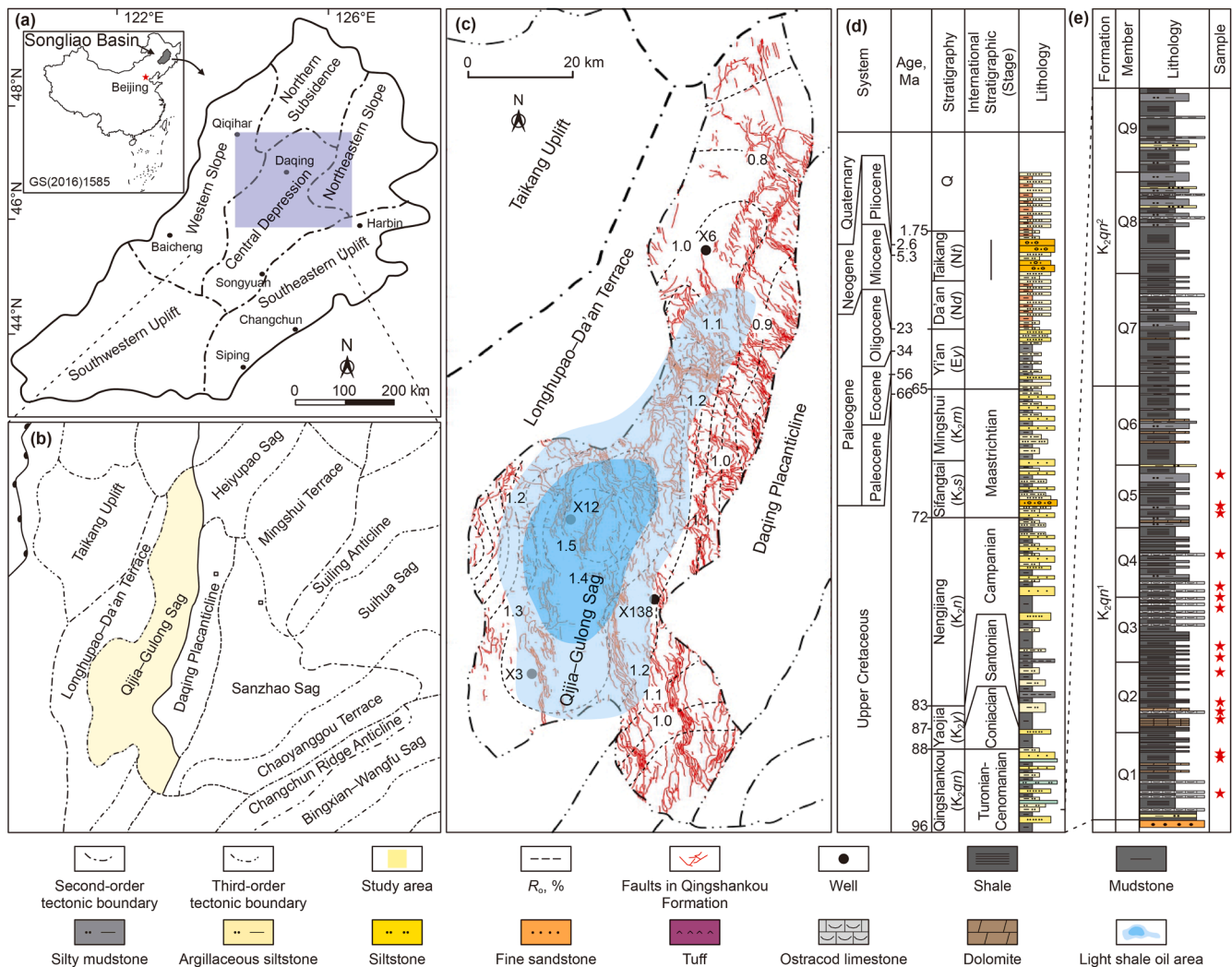


Fig. 1. Location and geological framework of the Qijia-Gulong Sag and lithostratigraphy of the Gulong shale in the Songliao Basin. **(a)** First-order tectonic units of the Songliao Basin and the regional location of the study area; **(b)** second-order tectonic units in the northern part of the Central Depression; **(c)** thermal maturity of the Gulong shales, major faults, light shale oil area, modified after (Cui et al., 2022; Sun et al., 2023; Huang et al., 2024, 2025), and sampling wells; **(d)** integrated stratigraphic column of the Qingshankou Formation and overlying sedimentary layers; **(e)** lithological characteristics and sampling levels of the Gulong Shale (Q1–Q9). Note: the term “Gulong Shale” in this study refers only to the Gulong shale interval within the Qingshankou Formation, specifically Member 1 and the base of Member 2; it does not include Members 1 and 2 of the Nenjiang Formation.

3. Samples and methods

3.1. Sample preparation and analytical workflow

A total of sixteen samples were selected from four wells (X6, X12, X138, and X3), including fibrous and laminated calcite veins, barite veins, and ostracod limestones, covering sublayers Q1 to Q5 (Figs. 1(d), (e), 2). For each sample, core depth, sublayer position, host lithology, and brief descriptions of core and vein occurrence were documented during sampling and are summarized in [Supplementary Table S1](#). Petrographic screening under transmitted light and fluorescence was first conducted to identify well-preserved, multi-stage fluid inclusion assemblages and to exclude samples affected by significant re-equilibration or deformation. For each selected sample, two mirrored thin sections (30 μ m thick) and, where applicable, a mount for in situ U–Pb dating (2.5 cm $\times$ 0.5 cm) were prepared to facilitate petrographic correlation between fluid inclusion observations and U–Pb analytical spots. Fluid inclusion assemblages were classified based on their petrographic relationships. Cathodoluminescence imaging and

SEM–EDS analyses were then used to establish the relative diagenetic sequence of the host minerals. Microthermometric measurements, fluorescence spectroscopy, and Raman spectroscopy were subsequently applied to characterize fluid inclusion phase states, fluorescence characteristics, and fluid types. Burial–thermal history reconstruction was then integrated with the petrographic and geochronological data for temporal interpretation.

3.2. Fluid inclusion analysis

Microscopic identification and observation of fluid inclusions were conducted using an OLYMPUS BX53M dual-channel microscope equipped with transmitted light and ultraviolet (UV) fluorescence illumination. Observations were performed at magnifications ranging from 25 $\times$ to 630 $\times$. Fluid inclusion assemblages (FIAs) were identified following the criteria of Goldstein (2001), defined as groups of inclusions trapped under similar physicochemical conditions during a single fluid event, and therefore characterized by consistent vapor–liquid ratios, bubble

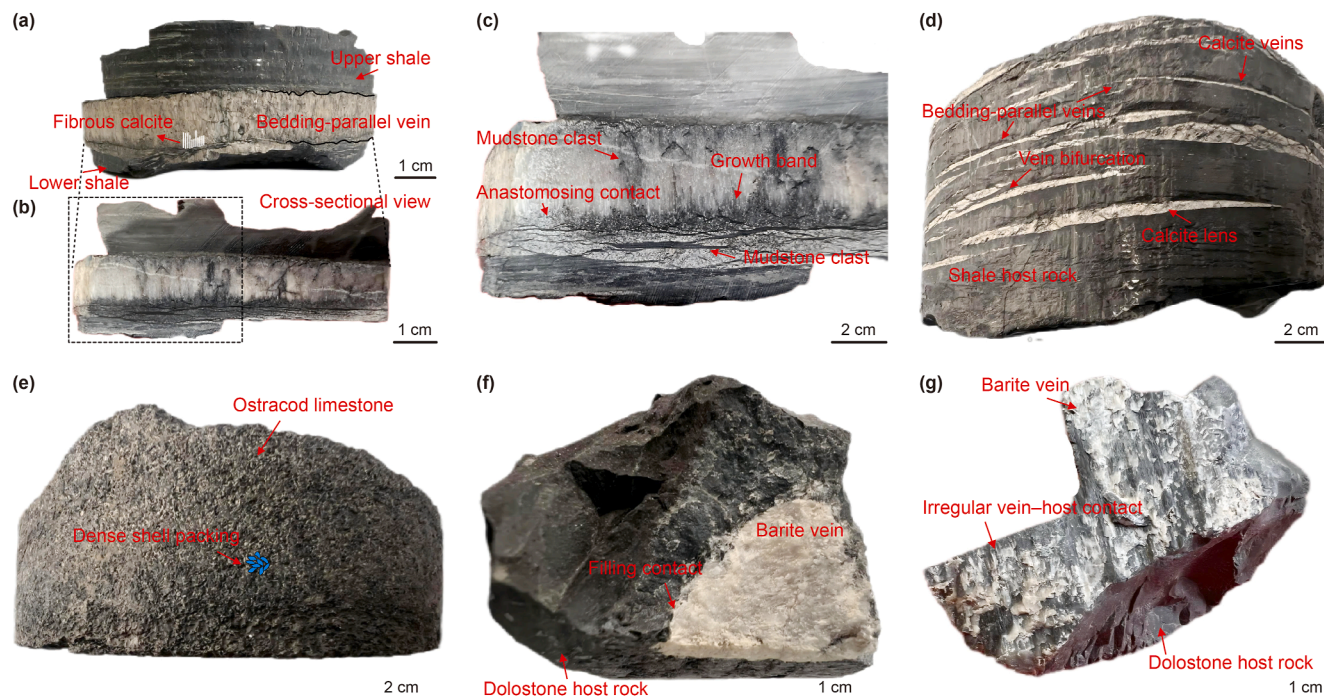


Fig. 2. Representative macroscopic photographs of study samples collected from the Gulong shale interval in the Qijia–Gulong Sag, Songliao Basin. Only representative vein and interbed samples related to the fluid inclusion analyses are shown. **(a, b)** Fibrous calcite vein sample from Well X138, K_2qn^1 at 1944.1 m: (a) original core photograph; (b) cross-sectional view of the vein in the core; **(c)** enlarged view of the boxed area in (b), showing fibrous calcite crystals and mudstone clasts; **(d)** fibrous calcite vein sample from Well X6, K_2qn^1 at 2346.5 m; **(e)** ostracod limestone sample from Well X12, K_2qn^1 at 2408.3 m; **(f)** barite vein sample from Well X3, K_2qn^1 at 2459.5 m; **(g)** barite vein sample from Well X3, K_2qn^1 at 2460.3 m.

sizes, and homogenization temperatures (T_h) (Goldstein, 2001). In this study, FIAs were further evaluated based on petrographic occurrence, including their distribution along growth zones, occurrence within isolated intragranular domains, or alignment along healed microfractures; where petrographic relationships were sufficiently clear, inclusions were classified as primary, pseudosecondary, or secondary. Such assemblages are considered to have formed under near-equilibrium conditions and to have experienced minimal post-entrapment modification, allowing them to be used reliably for microthermometric analysis and statistical evaluation of trapping temperatures (Chi and Lu, 2008).

Microthermometric measurements were performed using an OLYMPUS BX53M-HCS621GXY fluid inclusion system equipped with an INSTEC HCP621G-PM heating–cooling stage. Observations were carried out at magnifications of $25\times$ to $1000\times$. During heating, the initial temperature ramp rate was set to $10^\circ\text{C}/\text{min}$ and reduced to $3^\circ\text{C}/\text{min}$ as inclusions approached homogenization in order to improve measurement precision. The heating–cooling stage operates over a temperature range of -190°C to 600°C , with a minimum ramp rate of $\pm 0.01^\circ\text{C}/\text{min}$, a temperature resolution of 0.01°C , and a stability of $\pm 0.05^\circ\text{C}$ above 25°C and $\pm 0.1^\circ\text{C}$ below 25°C . Freezing measurements were not systematically available for the present dataset. Therefore, salinity estimates are not reported here, and the interpretation is based primarily on homogenization temperatures, petrographic relationships, and comparison with coexisting aqueous inclusions where available. For trapping-age interpretation, representative temperatures were selected on an FIA basis rather than from isolated minimum or maximum T_h values. Where possible, FIA-constrained T_h ranges were evaluated together with petrographic relationships and coexisting aqueous inclusions for burial–thermal history-based temporal interpretation.

Phase states and inorganic gas components of selected fluid inclusions were further characterized using laser Raman

spectroscopy, conducted with an OLYMPUS BX41 microscope coupled to a HORIBA LabRAM HR Evolution Raman spectrometer. Raman analysis was used primarily for phase identification of fluid inclusions, including oil-bearing, bitumen-bearing, and aqueous inclusions, and was treated as supporting evidence for fluid-type discrimination rather than as a basis for detailed interpretation of hydrocarbon composition or maturity.

3.3. Identification of diagenetic stages of host minerals

Establishing the temporal framework for fluid inclusion trapping requires precise differentiation of diagenetic stages in host carbonate and sulfate minerals. Generations of vein minerals were distinguished using petrographic relationships, cathodo-luminescence (CL) characteristics, and microscale compositional variations. Differences in luminescence color, intensity, and zoning patterns in CL images enabled the identification of distinct growth phases and overprinting relationships among cement generations (Götze, 2012). These textural observations were supplemented by SEM–EDS analyses, which provided mineralogical and compositional constraints for distinguishing calcite, dolomite, and barite phases, as well as their internal chemical heterogeneity. Detailed EDS spectra, spot locations, and acquisition settings are provided in Supplementary Fig. S5. Cathodoluminescence analyses were conducted with a Leica DM4500P polarizing microscope equipped with a BII CLF-2 cathodoluminescence system.

3.4. Fluorescence spectral and chromatic characterization of oil inclusions

To systematically characterize the fluorescence properties of hydrocarbon inclusions from different diagenetic stages in veins of the Qingshankou Formation, representative inclusions were analyzed using in situ fluorescence spectroscopy and chromatic

parameterization. Fluorescence spectra were acquired with an OLYMPUS FLUOVIEW FV3000 laser confocal microscope equipped with a spectral detection module. All measurements were performed under identical excitation and acquisition conditions to ensure comparability among samples. The spectra were used to determine the wavelength of maximum emission ($\lambda_{\max}$) and spectral shape, which may reflect variations in hydrocarbon composition and thermal maturity. To minimize subjectivity associated with visual color assessment and variations in excitation intensity or observation conditions, fluorescence colors were further quantified using the Commission Internationale de l'Éclairage (CIE) 1931 chromaticity system. Fluorescence spectra were converted into CIE chromaticity coordinates, here termed fluorescence spectral CIE (FS-CIE). Separately, RGB values extracted from fluorescence micrographs acquired under standardized imaging conditions were converted into CIE chromaticity coordinates, here termed image-based fluorescence CIE (IF-CIE). The EqHIR₀ calibration used in this study was established from the CIE parameters and was subsequently used as an auxiliary maturity constraint in trapping-age interpretation.

3.5. *In situ* U–Pb dating of host minerals

To obtain absolute temporal constraints on key fluid events related to shale oil accumulation, hydrocarbon-bearing fluid inclusions and their host vein minerals were analyzed for entrapment timing and *in situ* U–Pb dating, respectively. Because hydrocarbon inclusions themselves cannot be directly dated and carbonate U–Pb systems are sensitive to common Pb and matrix effects, strict criteria were applied during sample selection and analytical procedures to improve data reliability.

Specifically, host minerals containing hydrocarbon inclusions and coeval aqueous inclusions were selected based on petrographic observations, CL imaging, and FIA relationships. A mirrored thin-section strategy was adopted to facilitate petrographic correlation between dated spots and fluid inclusion assemblages. Prior to analysis, pre-screening by LA-ICP-MS was performed to identify domains with relatively low common Pb and higher U contents.

In situ U–Pb analyses were conducted using a RESOLUTION SE-S155 excimer laser ablation system coupled to a Thermo Fisher iCAP RQ ICP-MS. Data reduction was performed using Iolite, and Tera–Wasserburg concordia plots and age calculations were carried out using IsoplotR (online version). The international reference material AHX-1d (236.9 ± 2.4 Ma) was used for quality control. Because low-U carbonates with elevated common Pb may pose analytical challenges for quadrupole ICP-MS systems, domains with relatively higher U contents and lower common Pb were preferentially selected during pre-screening, and age interpretation was based on data arrays showing geologically reasonable concordia regression behavior. Detailed regression parameters, spot selection information, and analytical data are provided in [Supplementary Table S3](#).

4. Results

4.1. Petrographic characteristics

Samples used for fluid inclusion analysis and *in situ* U–Pb dating were collected from mineral veins developed in the first member of the Qingshankou Formation in Wells X6, X12, X138 and X3. The samples display pronounced variations in lithology, vein morphology, and contact relationships with the host shale across different wells.

In Well X138, calcite veins exhibit a dry, irregular fibrous–columnar surface texture ([Fig. 2\(a\)](#)). Cross sections show dark muddy fragments enclosed within the fibrous calcite aggregates ([Fig. 2\(b\)](#)), and higher magnification images reveal an interlocking mosaic contact between the fibrous calcite and the surrounding shale ([Fig. 2\(c\)](#)). In Well X6, fibrous calcite veins are widely developed and occur predominantly in sub-horizontal orientations, crosscutting or running parallel to shale lamination and commonly forming interlayered, anastomosing contacts with the host shale ([Fig. 2\(d\)](#)). Samples from Well X12 are massive in appearance, with rough surfaces and densely packed shell fragments; weak lamination and irregular depositional textures are locally preserved ([Fig. 2\(e\)](#)). In Well X3, barite veins are developed. At 2459.5 m depth, the barite vein shows a filling contact with the carbonate host rock ([Fig. 2\(f\)](#)), whereas at 2460.3 m the vein is locally truncated by fractures, forming a crosscutting contact relationship ([Fig. 2\(g\)](#)).

Cathodoluminescence (CL) imaging was conducted on representative vein samples to identify different generations of mineral growth. In fibrous calcite veins from Wells X138 and X6, two distinct generations of calcite cement can be distinguished based on CL color and texture ([Fig. 3\(a\)–\(e\)](#)). In Well X138, the early-stage calcite (Cal-I) exhibits a dark brown luminescence and forms the primary fibrous vein framework, whereas later calcite (Cal-II) fills fractures within the earlier vein and displays bright orange-red luminescence; minor dolomite locally accompanies the Cal-II phase ([Fig. 3\(b\)](#) and [\(e\)](#)). In Well X6, Cal-I shows red-brown luminescence, while Cal-II is characterized by orange-red luminescence. Combined CL observations and SEM–EDS analyses indicate systematic geochemical elements differences between calcite generations. In Well X138, Cal-I displays lower Fe/Mn ratios and red-brown luminescence, whereas Cal-II shows higher Fe/Mn ratios and orange-red luminescence ([Fig. 3\(a\)](#)). In the ostracod limestone sample from Well X12, calcite cement occurs both within shell interiors and along fractures, defining two discrete vein-forming episodes ([Fig. 3\(f\)](#) and [\(g\)](#)). Based on fluid inclusion assemblages and petrographic relationships in Well X3, barite veining can be divided into three stages. Stage I represents diagenetic fracture filling, whereas Stages II and III correspond to later tectonically induced fracture sealing events. In addition, CL imaging reveals the presence of calcite crystals within the surrounding dolostone host rock ([Fig. 3\(h\)](#) and [\(i\)](#)). Together, these petrographic observations indicate that vein formation in the Qingshankou Formation involved multiple generations of mineral precipitation associated with both diagenetic and tectonic processes, providing a petrographic basis for integrating fluid inclusion data and U–Pb dating in subsequent analysis.

4.2. Distribution and spectral characteristics of fluid inclusion assemblages

Multiple types of fluid inclusion assemblages (FIAs) are developed in veins from the Qingshankou Formation Member 1 in the Qijia–Gulong Sag ([Fig. 4](#)). Hydrocarbon-bearing inclusions are commonly arranged in clusters or bead-like trails and typically display elongate or elliptical shapes; occasionally coexisting with aqueous inclusions ([Fig. 4\(a\)](#)). Where petrographic relationships were sufficiently clear, inclusions illustrated in [Fig. 4](#) were further interpreted as primary to pseudosecondary in early calcite/barite domains and mainly as secondary or fracture-related in later healed domains. Among them, hydrocarbon inclusion assemblages (HIAs) are most abundant and mainly include two-phase oil inclusions and bitumen inclusions ([Fig. 4\(g\)](#) and [\(q\)](#)).

Raman spectroscopy reveals distinct spectral features for different inclusion types. Oil inclusions show broad Raman bands

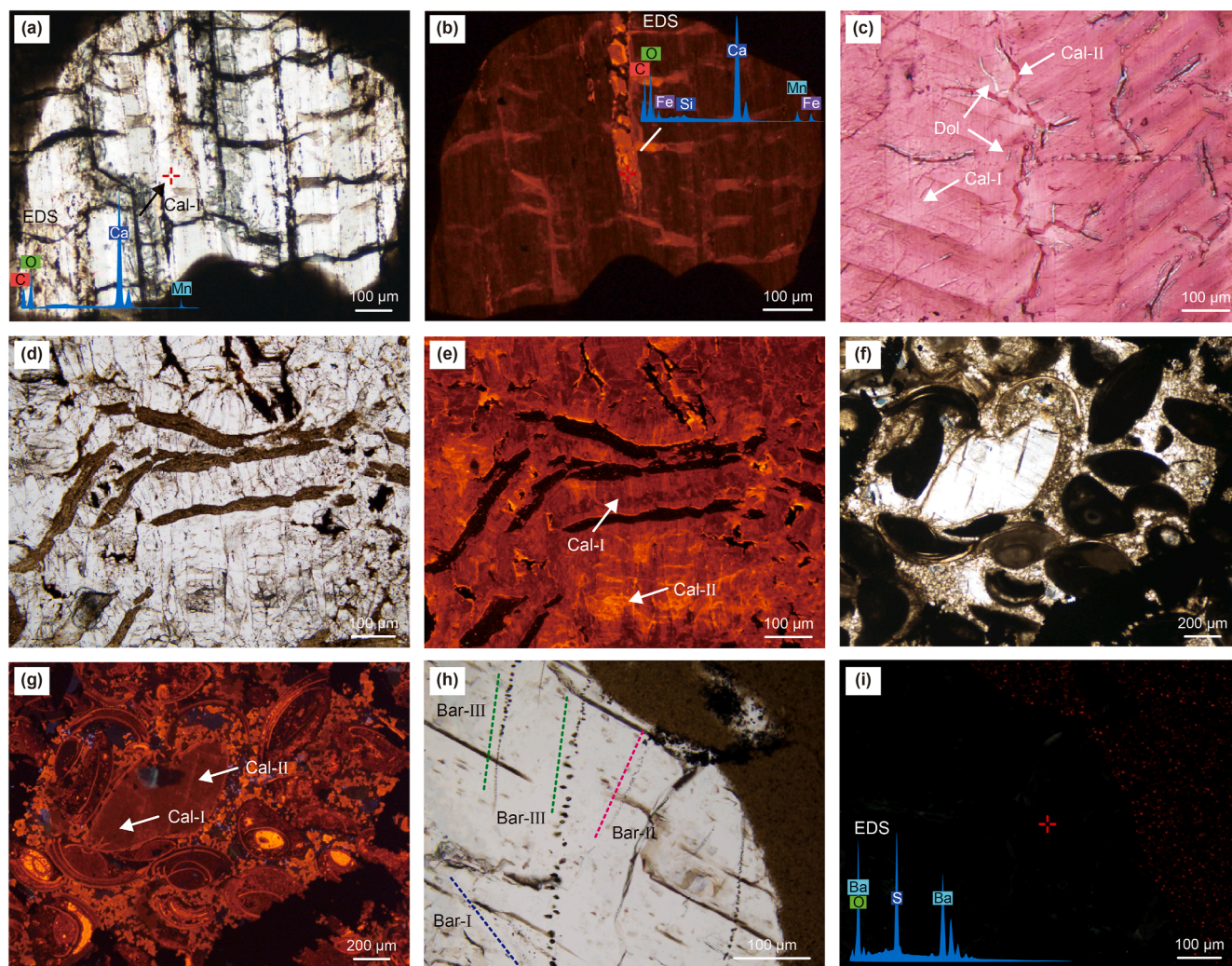


Fig. 3. Plane-polarized light (PPL) and cathodoluminescence (CL) micrographs of representative vein-related samples from the Gulong shale interval in the Qijia–Gulong Sag. (a–c) Well X138, K_2qn^1 at 1944.1 m, showing two generations of calcite cement in the vein and coexisting dolomite: (a) PPL image at 50×; (b) CL image at 50×; (c) PPL image after alizarin red staining at 50×; (d, e) Well X6, K_2qn^1 at 2346.5 m, fibrous calcite vein under PPL and CL, showing mudstone fragments entrained within the vein; (f, g) Well X12, K_2qn^1 at 2408.3 m, PPL and CL images of ostracod limestone at 50×; (h, i) Well X3, K_2qn^1 at 2459.5 m, PPL and CL images of a barite vein, together with the corresponding EDS spectra. Further petrographic details for distinguishing vein generations are provided in [Supplementary Figs. S1–S4](#), and the original EDS data are presented in [Supplementary Fig. S5](#).

that do not allow further compositional subdivision ([Fig. 4\(e\)](#)). Bitumen inclusions display characteristic D and G bands, with the D band centered at 1330.13 cm^{-1} and the G band at 1605.06 cm^{-1} ([Fig. 4\(g\)](#)). Aqueous inclusion domains show broad spectral features, with elevated background intensity approximately between 2700 and 3100 cm^{-1} ; these features are further discussed in [Supplementary Fig. S6](#).

Under ultraviolet fluorescence microscopy, hydrocarbon inclusions commonly display yellow-green, blue-white, and blue fluorescence. In Well X6, Cal-I inclusions show yellow-green fluorescence ([Fig. 4\(j\)](#)), whereas Cal-II inclusions exhibit blue-white fluorescence ([Fig. 4\(n\)](#)). In Well X12, Cal-I oil inclusions show predominantly blue fluorescence ([Fig. 4\(a\)](#)). In transmitted light, the liquid phase of oil inclusions is typically colorless and transparent, with clearly visible brown gas bubbles.

Statistical analysis of fluorescence spectral parameters, including peak emission wavelength (λ_{max}), red–green quotient (Q), and QF535, shows that λ_{max} values range from 451.24 nm to 546.32 nm ([Fig. 5\(a\)](#)), and fluorescence spectral CIE (FS-CIE) chromaticity parameters indicate a systematic shift from yellow-green to blue fluorescence ([Fig. 5\(b\)](#)). Yellow-green fluorescent

inclusions have λ_{max} values of 525.84 nm – 546.32 nm , Q values of 0.336 – 0.546 , and QF535 values of 1.10 – 1.49 . Blue-white fluorescent inclusions show λ_{max} values of 498.52 nm – 516.34 nm , Q values of 0.25 – 0.41 , and QF535 values of 0.78 – 1.08 . Blue fluorescent inclusions are characterized by λ_{max} values of 451.24 nm – 483.85 nm , Q values of 0.06 – 0.22 , and QF535 values of 0.205 – 0.478 .

4.3. Microthermometric results

Homogenization temperatures vary systematically among wells and diagenetic stages ([Fig. 6](#)). In X12, Cal-I oil inclusions homogenize at 104.2 – $116.8\text{ }^\circ\text{C}$, with associated aqueous inclusions at $128.2\text{ }^\circ\text{C}$, whereas Cal-II oil inclusions homogenize at 76.8 – $98.3\text{ }^\circ\text{C}$ with aqueous inclusions at $113.8\text{ }^\circ\text{C}$ ([Fig. 6\(a\)](#)).

In X138, Cal-I oil inclusions homogenize at 122.3 – $156.8\text{ }^\circ\text{C}$, with coexisting aqueous inclusions at $148.2\text{ }^\circ\text{C}$, whereas Cal-II inclusions homogenize at 91.9 – $118.6\text{ }^\circ\text{C}$, with aqueous inclusions at $125.3\text{ }^\circ\text{C}$ ([Fig. 6\(b\)](#)). In X6, Cal-I oil inclusions homogenize at 85.6 – $128.3\text{ }^\circ\text{C}$, with associated aqueous inclusions at $122.5\text{ }^\circ\text{C}$, and

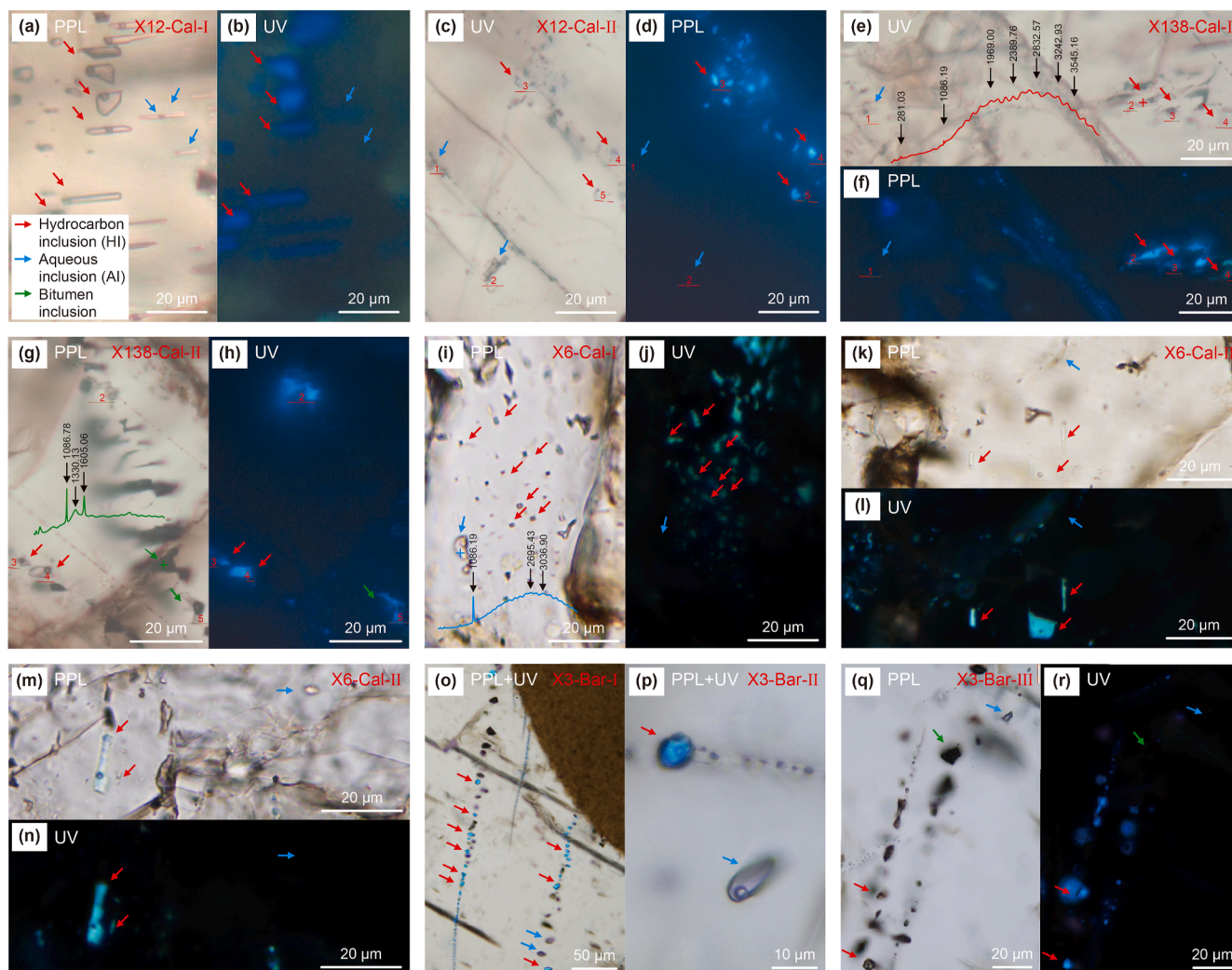


Fig. 4. Microphotographs of fluid inclusions in veins from the Gulong shale interval, Songliao Basin. (a–d) Well X12, K_2qn^1 at 2408.3 m: blue and blue-white fluorescent hydrocarbon inclusions and coexisting aqueous inclusions in ostracod limestone; (a, c) plane-polarized light (PPL) images; (b, d) ultraviolet (UV) fluorescence images. Under PPL, hydrocarbon inclusions are colorless and transparent, with dark brown to black vapor bubbles. (e–h) Well X138, K_2qn^1 at 1944.1 m: blue fluorescent hydrocarbon inclusions and associated aqueous inclusions in a fibrous calcite vein; (e, g) PPL images; (f, h) UV fluorescence images; (i–n) Well X6, K_2qn^1 at 2346.5 m: yellow-green and blue-white fluorescent hydrocarbon inclusions in a fibrous calcite vein; (i, k, m) PPL images; (j, l, n) UV fluorescence images; (o–r) Well X3, K_2qn^1 at 2459.5 m: blue fluorescent hydrocarbon inclusions and coexisting aqueous inclusions in barite; (o, q) PPL images; (r) UV fluorescence image; (p) merged PPL and UV image. Annotations indicate the occurrence of inclusions within host minerals or along healed microfractures. Where petrographic relationships are sufficiently clear, inclusions in Cal-I and Bar-I are interpreted as primary to pseudosecondary, whereas inclusions in Cal-II, Bar-II, and Bar-III are interpreted mainly as secondary or fracture-related. The detailed relationships between fluid inclusion occurrence and petrographic domains are further shown in [Supplementary Figs. S1–S4](#), and the original Raman data are presented in [Supplementary Fig. S6](#).

Cal-II inclusions homogenize at 61.6–83.5 °C, with aqueous inclusions at 113.2 °C ([Fig. 6\(c\)](#)).

Barite veins in X3 record a broader range. Bar-I oil inclusions homogenize at 113.2–116.7 °C with aqueous inclusions at 168.5 °C, Bar-II at 72.5–107.5 °C with aqueous at 137.8 °C, and Bar-III at 41.8–56.2 °C with aqueous at 126.7 °C, reflecting progressively cooler fluid regimes ([Fig. 6\(d\)](#)).

4.4. In situ U–Pb dating of host minerals

Two robust in situ U–Pb age populations were obtained for vein-hosted calcite associated with hydrocarbon inclusions. In Well X6, yellow-green fluorescent hydrocarbon inclusions are hosted in Cal-I calcite veins dated at 65.3 ± 4.8 Ma (MSWD = 0.51, $N = 49$) ([Fig. 7\(a\)](#)). Uranium concentrations range from 0.0572 to 1.401 $\mu\text{g/g}$ (mean 0.154 $\mu\text{g/g}$), with an initial $^{207}\text{Pb}/^{206}\text{Pb}$ ratio of 0.8585. In Well X138, blue fluorescent hydrocarbon inclusions are

hosted in Cal-I calcite veins dated at 58.2 ± 5.2 Ma (MSWD = 0.32, $N = 71$) ([Fig. 7\(b\)](#)). Uranium concentrations range from 0.1352 to 4.86 $\mu\text{g/g}$ (mean 0.821 $\mu\text{g/g}$), with an initial $^{207}\text{Pb}/^{206}\text{Pb}$ ratio of 0.8498. These ages directly constrain the timing of hydrocarbon-related fluid activity recorded by the vein-hosted inclusion assemblages. The corresponding spot-level carbonate U–Pb isotope ratio data are provided in [Supplementary Tables S2 and S3](#).

5. Discussion

5.1. Fluorescence characteristics of hydrocarbon inclusions and their significance as abundance indicators

5.1.1. Fluorescence characteristics of hydrocarbon inclusions as indicators of thermal maturity

Hydrocarbon inclusion fluorescence parameters have long been used as proxies for oil maturity, among which the red–green

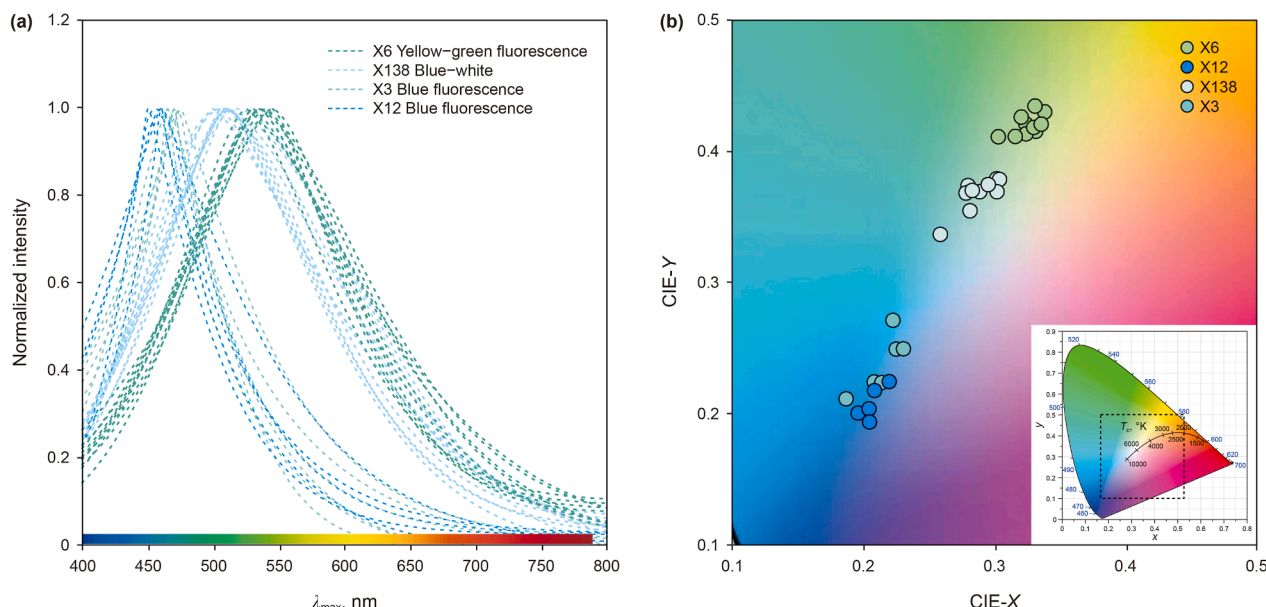


Fig. 5. Fluorescence spectra and CIE chromaticity of hydrocarbon inclusions from the K_2qn^1 veins in the Qijia–Gulong Sag. (a) Representative fluorescence spectra of hydrocarbon inclusions; (b) CIE 1931 chromaticity diagram showing the distribution of inclusion fluorescence colors.

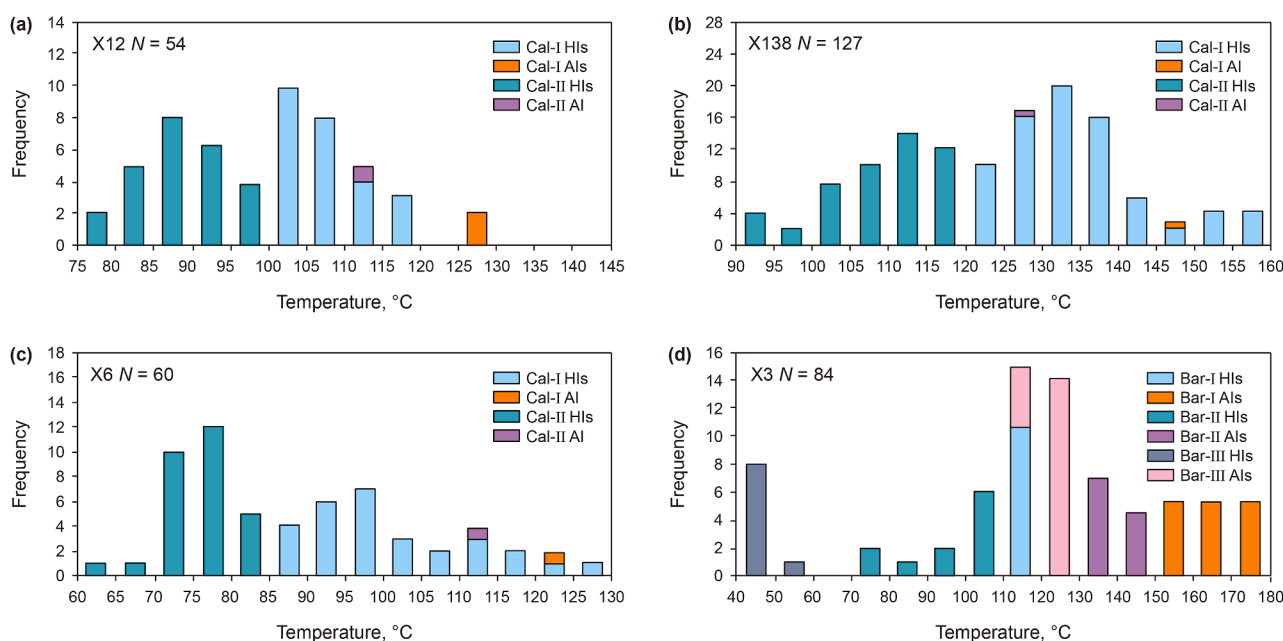


Fig. 6. Histograms of homogenization temperatures (T_h) of fluid inclusions in veins from the Gulong shale interval in the Qijia–Gulong Sag. HI denotes hydrocarbon inclusions, and AI denotes aqueous inclusions. (a) Well X12, K_2qn^1 at 2408.3 m, ostracod limestone; (b) Well X138, K_2qn^1 at 1944.1 m, calcite vein; (c) Well X6, K_2qn^1 at 2346.5 m, calcite vein; (d) Well X3, K_2qn^1 at 2459.5 m, barite vein.

ratio (Q) is widely applied to characterize the thermal maturity of inclusion-hosted hydrocarbons (Hagemann and Hollerbach, 1986). A higher Q value generally corresponds to lower maturity, whereas $QF535$, which reflects the relative contribution of long-wavelength fluorescence, is commonly interpreted as an indicator of higher molecular-weight components and therefore lower maturity oils (Burruss, 1991; Li et al., 2010). Based on the fluorescence spectral results presented in Section 4.2, yellow-green fluorescent inclusions from Well X6 yield a spectral CIE-derived equivalent R_o estimate of approximately 1.01%, whereas blue fluorescent inclusions from Well X12 yield values of up to

approximately 1.52%, consistent with the regional maturity pattern of the study area (Fig. 8(a)).

Although fluorescence spectroscopy is widely recognized as an effective tool for maturity assessment, most previous studies rely on discrete spectral parameters (Zhu et al., 2024), and continuous evolutionary trends between fluorescence color and thermal maturation are rarely documented due to limited datasets (Si et al., 2018b; Zuo et al., 2024; Zou et al., 2024). This limitation becomes particularly significant at high maturity levels, where fluorescence color differences diminish and qualitative discrimination becomes increasingly uncertain (Liu and Eadington, 2005).

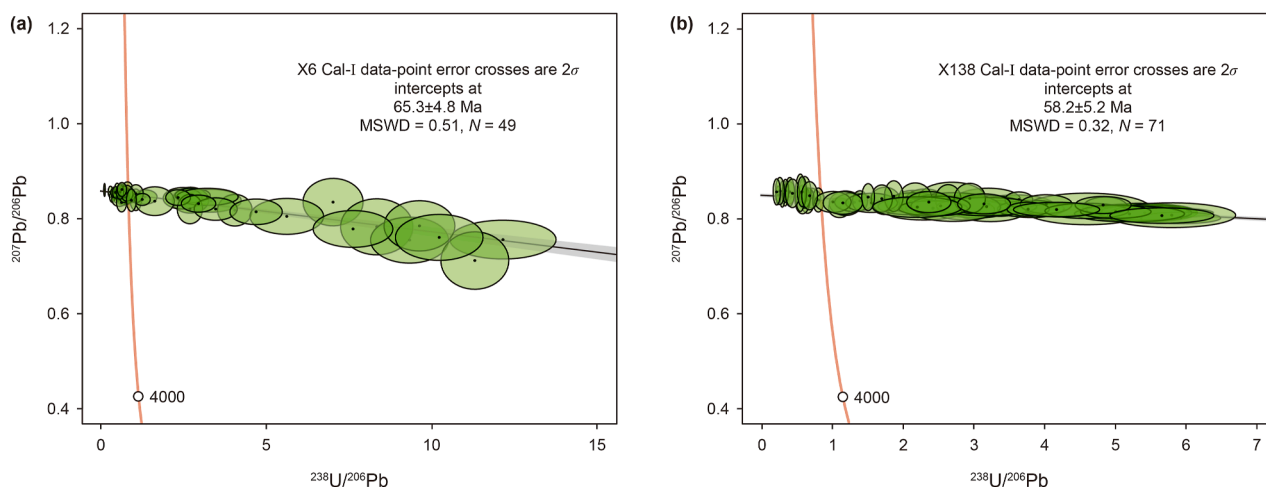


Fig. 7. In situ U–Pb dating results of calcite veins hosting fluid inclusions from the Gulong shale interval in the Qijia–Gulong Sag. **(a)** Well X6, K_2qn^1 at 2346.5 m; **(b)** Well X138, K_2qn^1 at 1944.1 m.

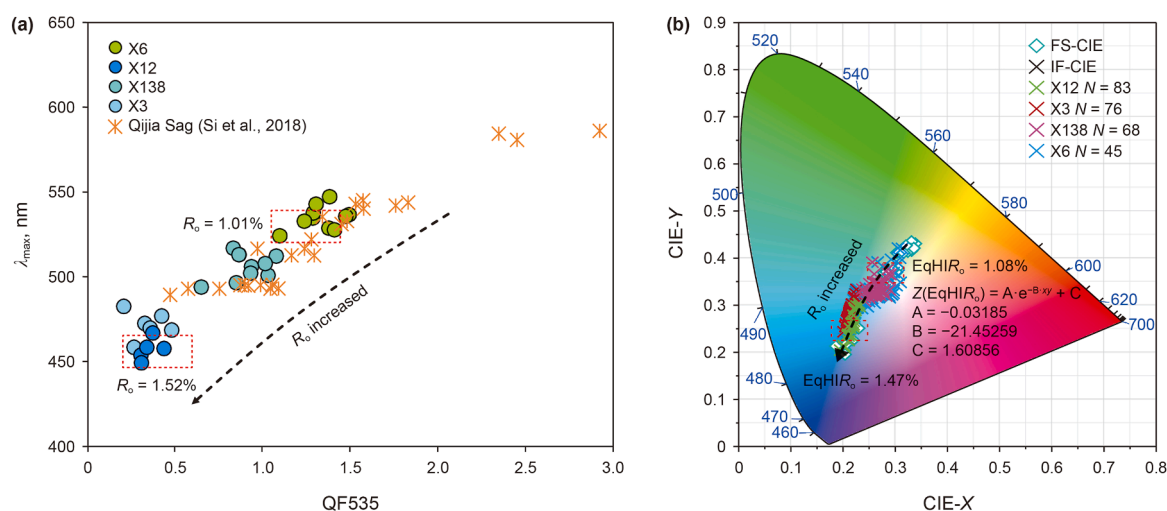


Fig. 8. Relationships between fluorescence parameters and chromaticity of hydrocarbon inclusions from the K_2qn^1 in the Qijia–Gulong Sag. **(a)** Relationship between fluorescence peak wavelength (λ_{max}) and QF535; **(b)** CIE 1931 chromaticity diagram of hydrocarbon inclusions.

To address this issue, we introduce the CIE 1931 chromaticity system to convert RGB color information extracted from fluorescence micrographs into a unified chromaticity space. Using the CIE-X and CIE-Y parameters, the fluorescence colors of hydrocarbon inclusions are semi-quantitatively characterized (image-based fluorescence CIE semi-quantitative method, IF-CIE). This approach transforms subjective color observations into continuous, reproducible numerical parameters, allowing a more robust description of fluorescence evolution with increasing maturity. Combining spectral parameters with CIE chromaticity data reveals a systematic progression from yellow-green to blue-white and finally blue fluorescence, accompanied by a spatial shift from the northern Qijia–Gulong area toward the depression center. This pattern is consistent with the previously reported “blue-shift” of hydrocarbon inclusion fluorescence with increasing maturity (Geddes et al., 2009; Chen, 2014; Xu et al., 2017; Zuo et al., 2024). Distinct maturity stages occupy well-separated domains in CIE chromaticity space, while within individual vein samples the chromaticity parameters show near-linear continuous trends, reflecting the progressive and sustained nature of thermal evolution and hydrocarbon accumulation events (Fig. 8(b)).

CIE chromaticity parameters therefore provide a valuable supplementary proxy for identifying high-maturity light oil retention and late-stage microscale hydrocarbon redistribution. An empirical exponential regional relationship between CIE chromaticity and maturity was established using regression analysis, defining an equivalent hydrocarbon inclusion reflectance ($EqHIR_0$), which enables a quantitative description of fluorescence evolution with thermal maturity. The current single-point relative error of CIE-based maturity estimation for Qingshankou oil inclusions is approximately 5.9%, indicating a reasonable level of reliability. Details of the fitting procedure and model parameters are provided in the Supplementary data.

5.1.2. Significance of hydrocarbon inclusion abundance in veins

Hydrocarbon fluid inclusions are widely developed in mineral veins within shale oil-enriched intervals. In conventional petroleum systems, the Grains Containing Oil Inclusions (GOI) has long been used as an indicator of the intensity of hydrocarbon charge, where higher GOI values generally reflect more active hydrocarbon migration and accumulation processes and are often considered to correlate with the degree of petroleum enrichment (Liu

et al., 2003; Zou et al., 2007). However, in fine-grained, shale reservoirs, hydrocarbon inclusions are predominantly hosted by authigenic carbonate veins, and suitable detrital grain references are typically absent. As a result, the traditional GOI method based on the ratio of oil inclusions to detrital grains is difficult to apply directly in shale systems (Wang et al., 2006).

Given this limitation, we introduce an image-based quantitative approach using laser confocal fluorescence microscopy. Areas within veins containing hydrocarbon inclusions were delineated over comparable scan areas, and multiple fields of view were examined to minimize sampling bias. The distribution of hydrocarbon inclusions within these areas was then statistically analyzed, and the proportion of fluorescent hydrocarbon inclusion area relative to the calcite vein area within the delineated region was calculated as a proxy for the relative abundance of hydrocarbon inclusions in shale reservoirs (defined here as the image-based hydrocarbon inclusion area abundance index, IHI-AI) (Fig. 9(a)–(c)). Because this method does not rely on the presence of

detrital grains, it is more suitable for quantitative analysis in vein-dominated, shale reservoirs.

In the study area, the relative fluorescence area of hydrocarbon inclusions varies significantly among samples from different well areas. Samples from Wells X12 and X3 show relatively high fluorescence area proportions, whereas those from Wells X6 and X138 are comparatively lower (Fig. 9(d)). Comparison with current shale oil exploration results indicates that wells characterized by higher hydrocarbon inclusion fluorescence area proportions broadly correspond to zones enriched in high-maturity, light shale oil (Fig. 1).

When combined with fluorescence color characteristics, areas dominated by blue-fluorescent inclusions generally correspond to high-maturity, light oil enrichment zones, whereas yellow-green, blue-white fluorescence typically represent low-to-moderate, moderate-to-high, respectively. These observations suggest that quantitative analysis of hydrocarbon inclusion fluorescence area in veins provides a useful supplementary indicator for identifying

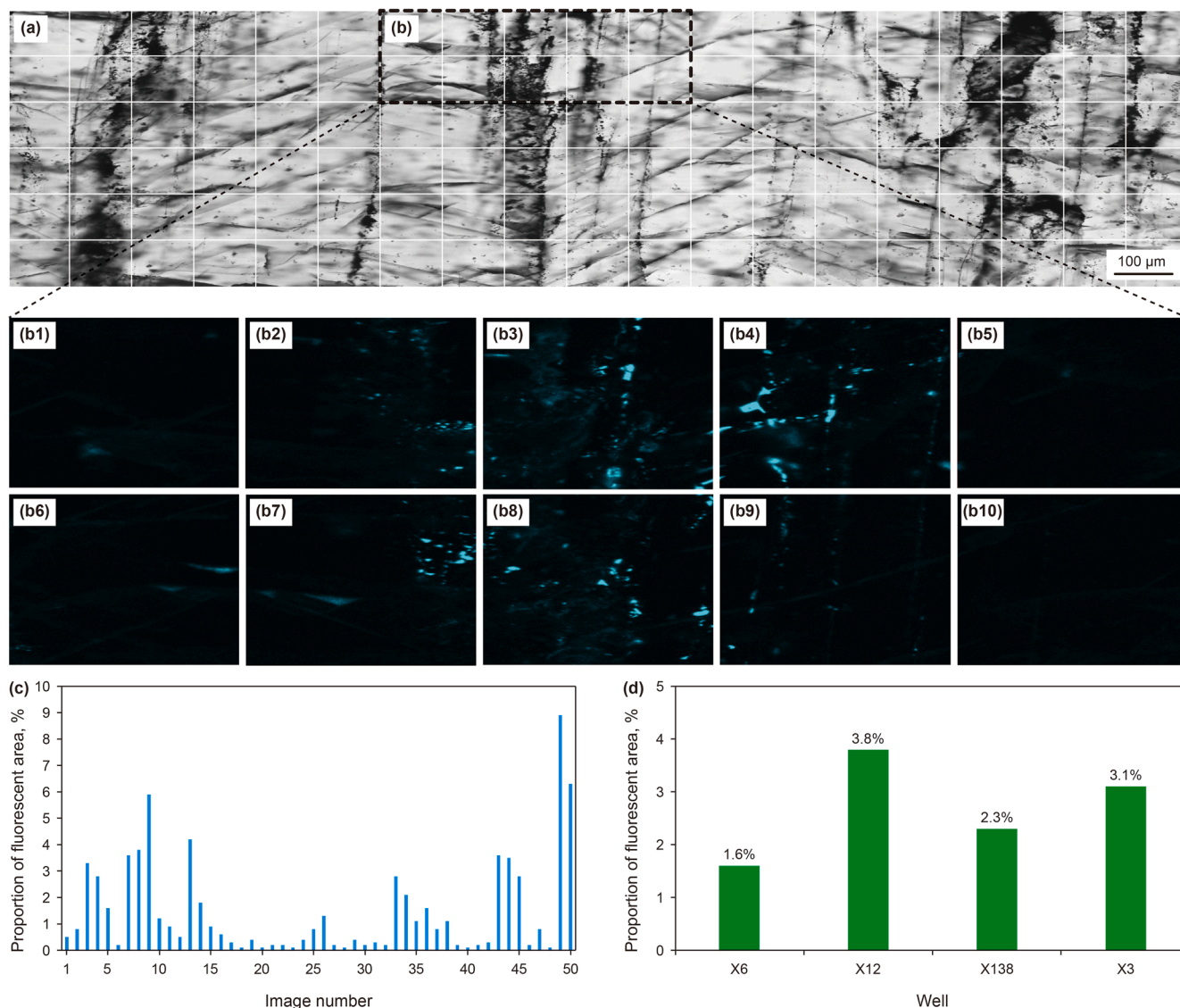


Fig. 9. Image-based abundance of hydrocarbon inclusions in the K_2qn^1 of the Qijia-Gulong Sag. (a) Confocal laser scanning micrograph showing the fluorescence area of hydrocarbon inclusions; (b) mapped distribution of hydrocarbon inclusions within the scanned area; (b1–b10) sequential fluorescence scans showing the continuity of inclusion distribution; (c) spatial distribution of hydrocarbon inclusion abundance in a calcite vein from Well X138 at 1944.1 m; (d) map showing the distribution of hydrocarbon inclusion abundance across the K_2qn^1 in the Qijia-Gulong Sag.

high-maturity light shale oil enrichment zones, and offers microscopic evidence for understanding shale oil accumulation processes and their spatial heterogeneity.

5.2. Reconstruction of the shale oil accumulation process

5.2.1. Timing constraints on shale oil accumulation

The absolute timing of shale oil accumulation is commonly inferred from the homogenization temperatures (T_h) of hydrocarbon and coexisting aqueous fluid inclusions combined with burial–thermal history modelling. However, in basins that have experienced multiple episodes of tectonic uplift and subsidence, such reconstructions are often affected by significant non-uniqueness and uncertainty (Gui et al., 2023). Integrating fluid inclusion records with in situ U–Pb dating of their host minerals provides an effective way to reduce this uncertainty and better constrain fluid trapping times (Drost et al., 2018; Lu et al., 2023). Nevertheless, carbonate U–Pb dating remains challenging because of generally low U concentrations, elevated common Pb, and matrix effects, which limit its analytical precision (Deng et al., 2023; Gui et al., 2025). At the same time, fluorescence spectral

characteristics of hydrocarbon inclusions reflect the thermal maturity evolution of palaeo-oil systems (Hagemann and Hollerbach, 1986; Burruss, 1991; Li et al., 2010). Based on these considerations, we establish a multi-parameter temporal framework integrating fluid inclusion thermal parameters, CIE chromaticity-based maturity indices, diagenetic sequencing of host minerals, in situ U–Pb ages, and burial history reconstruction (the FI–CIE–U–Pb–Burial integrated inversion approach) to improve the robustness of timing constraints on shale oil accumulation.

In Well X6, trapping ages of Cal-I stage fluid inclusions derived independently from homogenization temperatures and maturity indices ($E_{qHIR_0} \approx 0.92$) are approximately 66.8 Ma and 64.3 Ma, respectively, both of which are in good agreement with the in situ U–Pb age of the host calcite vein (65.3 ± 4.8 Ma) (Fig. 10(a)). Similarly, in Well X138, trapping ages of Cal-I inclusions derived from T_h and maturity ($E_{qHIR_0} \approx 0.94$) are approximately 59.3 Ma and 61.3 Ma, respectively, and are consistent with the U–Pb age of the host calcite (58.2 ± 5.2 Ma) (Fig. 10(b)). In contrast, Cal-II stage fluid activity occurred significantly later. In Well X6, Cal-II inclusions with $E_{qHIR_0} \approx 1.08$ yield a trapping age of approximately 36.2 Ma, whereas in Well X138, Cal-II inclusions with $E_{qHIR_0} \approx$

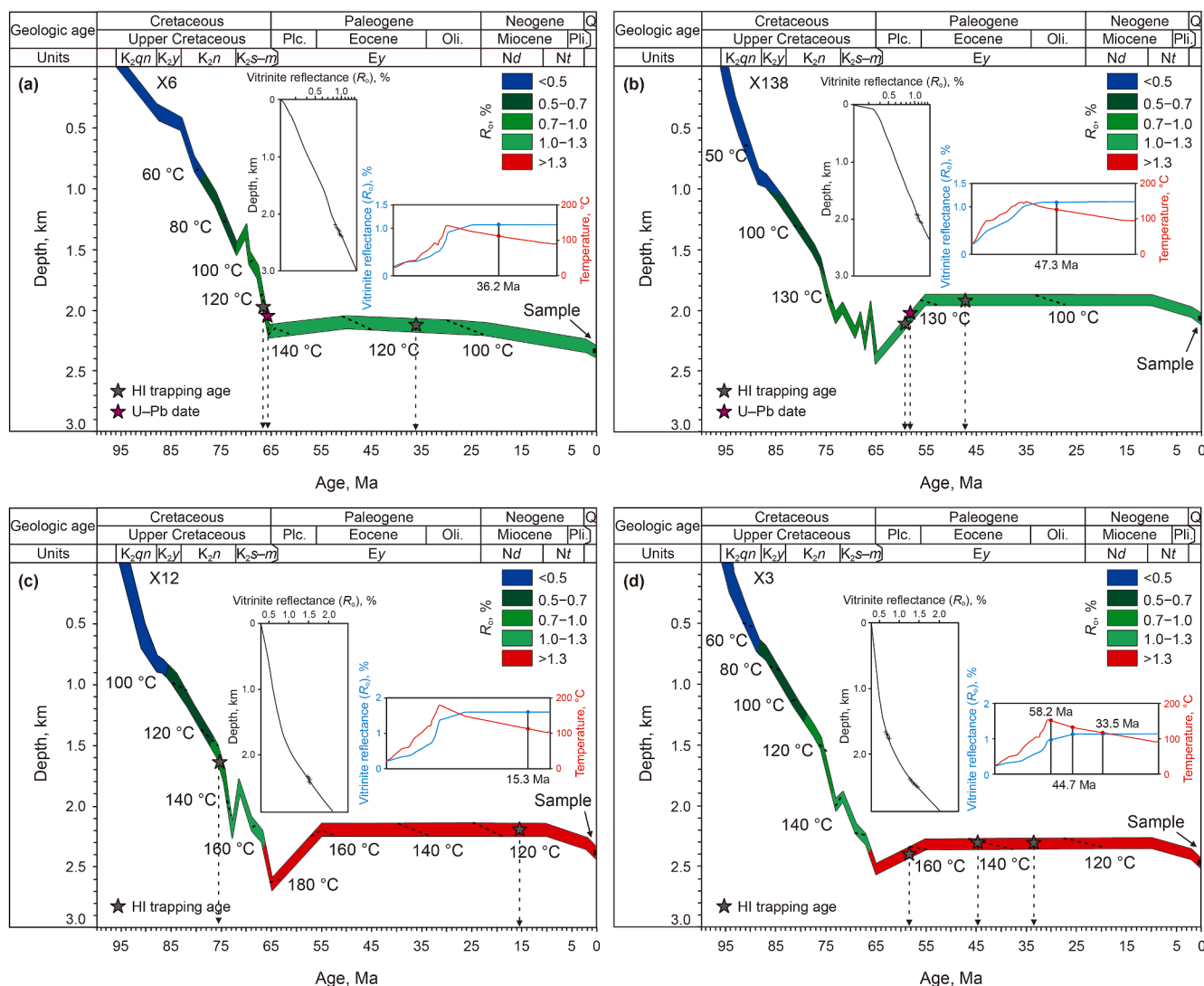


Fig. 10. Integrated burial history, thermal evolution, and hydrocarbon inclusion trapping ages for representative wells in the Qijia–Gulong Sag. (a) Well X6; (b) Well X138; (c) Well X12; (d) Well X3.

Table 1

Timing of oil accumulation in the Qingshankou Formation.

Stratigraphic unit	Well	Stage	T_h of HI, °C	T_h of coeval AI, °C	Host mineral	Time, Ma	Period	Evidence	Data source
K_2qn^1	Y51	I	50–70	/	/	/	Late Cretaceous	HI- T_h + Tectonic history + Burial history + Thermal history	Ren et al., 2019
K_2qn^1	/	II	80–100	/	/	/	End of the Cretaceous	Palaeotemperature history + Hydrocarbon generation history + Diagenetic evolution + Reservoir evolution Burial history + Diagenetic evolution Al- T_h + U-Pb dating + + Burial history	Meng et al., 2022
		III	110–130	110–130	/	/	Pliocene		
		/	/	/	/	/	Late Cretaceous End of the Cretaceous late Eocene-Oligocene		
K_2qn^1	/	/	/	/	/	56/45/32	/	Burial history + Diagenetic evolution	Li et al., 2025
K_2qn^1	X21	/	/	141.2–157.4	Calcite vein	44.7 ± 6.9	Eocene	Al- T_h + U-Pb dating + + Burial history	He et al., 2024
K_2qn^1	X6	I	85.6–128.3	122.5	Calcite vein	65.3 ± 4.8/66.8	End of the Cretaceous	HI- T_h + Co-Al- T_h + HI-thermal history + U-Pb dating + Diagenetic evolution + Burial history	(This study)
K_2qn^{2-3}	X138	II	61.6–83.5	113.2	Calcite vein	36.2	Eocene	HI- T_h + Burial history	Lin et al., 2014
		I	122.3–156.8	148.2	Calcite vein	58.2 ± 5.2/59.3	Paleocene		
		II	91.9–118.6	125.3	Calcite vein	47.3	Eocene		
	X12	I	104.2–116.8	128.2	Ostracod limestone	75.6	End of the Cretaceous		
		II	76.8–98.3	113.8	Ostracod limestone	15.3	Miocene		
	X3	I	113.2–116.7	168.5	Barite vein	58.2	Paleocene		
		II	72.5–107.5	137.8	Barite vein	44.7	Eocene		
		III	41.8–56.2	126.7	Barite vein	33.5	Oligocene		
	Qp1/J28	I	60–70	/	Quartz grains	/	Late Cretaceous		
		II	80–90	/	Quartz grains	/	End of the Cretaceous		
		III	100–110	/	Calcite cement	/	late Eocene-Oligocene		
K_2qn^{2-3}	Qp1/J28/YX58	I	60–70	80–90	Quartz grains	79–75	Late Cretaceous	HI- T_h + Co-Al- T_h + Burial history	Si et al., 2018
K_2qn^{2-3}	Qp1/J28/YX58	II	80–90	100–110	Quartz grains	69–65	End of the Cretaceous	HI- T_h + Co-Al- T_h + Burial history	
		III	100–110	120–140	Calcite cement				
		I	56.9–68.2	75.3–89.6	Quartz grains	79–75	Late Cretaceous		
K_2qn^{2-3}	W1–W8	II	75.4–89.1	90.3–109.4	Quartz grains	69–65	End of the Cretaceous	HI- T_h + Hydrocarbon generation history + Burial history	Chang et al., 2019
		III	90.2–111.3	110.4–144.9	Calcite cement				
		I	80–90	/	Quartz grains + Feldspar grains	73	Late Cretaceous		
K_2qn^{2-3}	Qp1	II	100–110	/	Calcite cement	65	End of the Cretaceous	HI- T_h + Al- T_h + Burial history	Wu et al., 2021
		I	65.7–68.2	85.3–92.7	Quartz grains	78–75	Late Cretaceous		
		II	75.5–90.2	97.5–108.9	Quartz grains	69–65	End of the Cretaceous		
K_2qn^{2-3}	X6	III	92.4–101.2	117.5–133.4	Calcite cement			Al- T_h + U-Pb dating + Burial history	He et al., 2024
		/	/	132.5–145.1	Calcite vein	69.9 ± 5.2	End of the Cretaceous		

HI stands for hydrocarbon inclusion, Co-AI denotes coexisting aqueous inclusion, T_h represents the homogenization temperature of the inclusion at room temperature.

1.18 yield a trapping age of approximately 47.3 Ma. These age differences suggest temporal heterogeneity in vein-forming fluid activity and associated in-source microscale hydrocarbon migration among different wells and diagenetic stages.

In the ostracod limestone of Well X12, early to middle diagenetic cementation commonly follows shell deposition (Feng et al., 2025). The Cal-I calcite shows little deformation, suggesting formation under relatively stable early diagenetic conditions. Combining regional constraints on early diagenetic timing (Li et al., 2025) with the T_h of associated aqueous inclusions (128.2 °C), the trapping age of Cal-I hydrocarbon inclusions is constrained at approximately 75.6 Ma. In contrast, fracture-healing Cal-II calcite associated with aqueous inclusions showing $T_h = 113.8$ °C corresponds to a trapping age of approximately 15.3 Ma (Fig. 10(c)).

In Well X3, barite veining is closely associated with hydrothermal infilling or sedimentary reworking processes (Qiao and Hu, 2014; He et al., 2024a). A few individual Stage Bar-I aqueous inclusions exhibit T_h values exceeding 180 °C, significantly higher than the maximum temperatures indicated by burial history modelling and thus providing supporting evidence for hydrothermal fluid involvement. However, the stable and reproducible T_h value of 168.5 °C was adopted as the representative temperature for quantitative interpretation. Combining maturity indices ($EqHIR_0 \approx 1.18\text{--}1.21$) with representative trapping temperatures, we infer that Bar-I, Bar-II, and Bar-III fluid events occurred at approximately 58.2 Ma, 44.7 Ma, and 33.5 Ma, respectively.

In some samples, trapping ages derived from fluid inclusion homogenization temperatures and maturity indices appear slightly older than the U–Pb ages of the host minerals. This apparent offset does not imply a physical inconsistency, but rather reflects systematic differences among the methods. Carbonate precipitation may span a finite time interval, and U–Pb ages represent integrated crystallization ages of the host minerals rather than the exact moment of individual inclusion trapping. In addition, minor open-system behavior of carbonate U–Pb systems and uncertainties in burial–thermal history reconstructions may introduce systematic offsets of several million years. Accordingly, the inferred trapping ages are best regarded as approximate time windows rather than precise instantaneous events. These uncertainties mainly reflect the combined effects of in situ carbonate U–Pb age uncertainty, burial–thermal history model uncertainty, and T_h -related uncertainty, including both measurement error and FIA-based temperature selection. Hydrocarbon inclusion T_h values were not treated here as direct equivalents of trapping temperature, but were interpreted together with co-genetic aqueous inclusions, FIA relationships, and burial–thermal history trends; their observed spread likely reflects multiple FIAs, multistage trapping, fluid compositional variability, and possible post-entrapment modification. Nevertheless, the results consistently indicate that hydrocarbon inclusion trapping and vein mineral precipitation were broadly synchronous at the geological time-scale, supporting the use of hydrocarbon inclusions as temporal markers for shale oil accumulation.

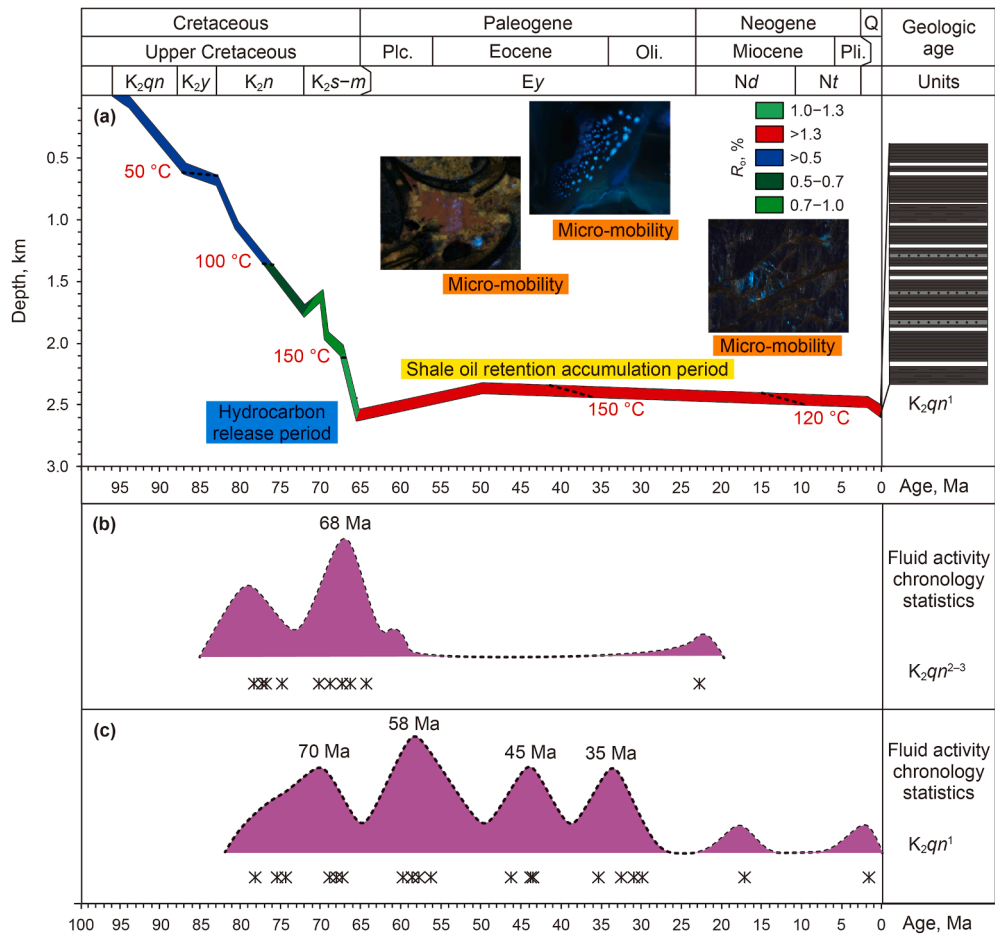


Fig. 11. Schematic reconstruction of the shale oil accumulation history of the K_2qn^1 in the northern Qijia-Gulong Sag, Songliao Basin.

5.2.2. Reconstruction of the shale oil accumulation process

Based on the chronological compilation of fluid activity since the deposition of the Qingshankou Formation (Table 1), a clear difference emerges between the accumulation of conventional reservoirs and shale oil within the K_2qn^1 interval (Fig. 11). Shale oil accumulation in the K_2qn^1 mainly occurred between 15.3 and 75.6 Ma, with a pronounced concentration between 40 and 60 Ma (Fig. 11(a)). In contrast, the main accumulation stage of the overlying K_2qn^2 and K_2qn^3 conventional reservoirs is constrained to 68.3–82.5 Ma (Fig. 11(b)) (Si et al., 2018b; Chang et al., 2019; Wu et al., 2021; He et al., 2024b), indicating a systematic temporal offset between conventional and shale oil systems.

Previous studies have shown that the Gaotaizi conventional reservoir experienced multi-stage charging (Si et al., 2018a). In comparison, our results indicate that shale oil accumulation in the K_2qn^1 postdated the main charging phase of the overlying conventional reservoirs. This implies that shale oil did not form synchronously with the peak hydrocarbon generation and expulsion, but instead accumulated progressively within the source rock after multiple episodes of generation, expulsion, and intrasource retention. This interpretation is consistent with the concept that shale oil represents a retained product of continuous hydrocarbon generation within source rocks, and it is directly supported here by the combined fluid inclusion and geochronological evidence.

After the initial retention of shale oil, multiple episodes of microscale hydrocarbon redistribution continued within the K_2qn^1 source interval. These processes are recorded by successive generations of hydrocarbon inclusions preserved in vein minerals. In particular, the intrasource migration of light oil was likely more active during the Yian Formation stage, which appears to be a key period controlling the present-day distribution of shale oil accumulations (Fig. 11(a)). The development of overpressured compartmentalized structures within the source rocks provided the physical framework for long-term hydrocarbon retention and subsequent redistribution (Huang et al., 2024). Within these compartments, microscale migration occurred both vertically and laterally in a continuous manner, offering a geological explanation for the commonly observed sequence of “accumulation–sealing–remigration” in shale oil systems.

Because large-scale systematic sampling of veins to fully reconstruct the accumulation history is inherently limited by data availability and preservation, we further examined the relationship between oil inclusion fluorescence characteristics and maturity trends. The CIE chromaticity evolution of oil inclusions indicates that shale oil accumulation in the K_2qn^1 was not the result of a short-lived event, but rather a progressive outcome of continuous hydrocarbon generation coupled with episodic intrasource redistribution. We therefore propose a “continuous generation–intrasource micromigration coupled accumulation” model for shale oil in the K_2qn^1 . In this model, continuous hydrocarbon supply includes continued hydrocarbon generation from organic matter and the possible secondary thermal transformation of hydrocarbons retained within the source rock. This model emphasizes the persistence of hydrocarbon generation and transformation within the source rock and the temporal decoupling between generation and accumulation at the scale of individual reservoirs.

Although this study provides direct fluid inclusion and geochronological support for this model, further integration with the evolution of pore structure, pressure systems, and mechanical stratigraphy will be required to fully evaluate its broader applicability and internal dynamics.

6. Conclusions

- (1) The vein systems within the Qingshankou Formation host abundant hydrocarbon and rare aqueous fluid inclusions, including oil–gas two-phase inclusions, bituminous inclusions and two-phase aqueous inclusions. Blue-fluorescent oil inclusions, characterized by fluorescence peak wavelengths ($\lambda_{\max}$) < 485 nm and CIE chromaticity coordinates X and Y < 0.3, indicate a relatively high level of thermal maturity. Their preferential abundance in the central Gulong Sag is spatially consistent with the distribution of highly mature, light shale oil, suggesting that fluorescence color and abundance can serve as indicators for favorable light-oil zones. The image-based fluorescence CIE chromaticity method (IF-CIE) and the image-based hydrocarbon inclusion abundance index (IHI-AI) provide useful supplementary indicators of maturity and potential enrichment.
- (2) In situ U–Pb dating of calcite veins yields ages of 65.3 ± 4.8 Ma and 58.2 ± 5.2 Ma. These results align with the trapping ages inferred for the associated oil inclusions, coexisting aqueous inclusions, and EqHIR_o. The FI-CIE–U–Pb–Burial integrated framework enables refined temporal constraints on shale oil accumulation. The trapping ages of hydrocarbon inclusions cluster at approximately 75.6 Ma, 58.2 Ma, 44.7 Ma, 36.2 Ma, 33.5 Ma and 15.3 Ma across different wells and diagenetic stages, indicating that the records of shale oil accumulation and intrasource micromigration were polyphase and temporally asynchronous processes rather than a single discrete event. The main shale oil accumulation stage is inferred to have occurred during deposition of the Yian Formation (ca. 60–25 Ma).
- (3) The accumulation timing of shale oil in the Member 1 of Qingshankou Formation shows spatiotemporal coupling with that of conventional reservoirs in Members 2 and 3, but is overall younger, providing evidence that shale oil represents a retained accumulation within the source rock. These results support a continuous generation–intrasource micromigration coupled accumulation model for lacustrine shale oil in the Songliao Basin.
- (4) Although the number of vein samples and inclusion datasets is limited, the integrated fluid inclusion and geochronological evidence provides new constraints on the dynamic processes of shale oil retention, redistribution and late-stage reorganization. Further studies integrating pore structure evolution and pressure–temperature history are required to fully evaluate the applicability and refinement of this accumulation model.

CRedit authorship contribution statement

Yue Huang: Writing – review & editing, Writing – original draft, Visualization, Validation, Software, Methodology, Investigation, Formal analysis, Data curation, Conceptualization. **Qing-Chun Jiang:** Writing – review & editing, Writing – original draft, Supervision, Resources. **Jian Chang:** Writing – review & editing, Validation, Supervision, Resources, Project administration, Funding acquisition, Data curation, Conceptualization. **Nan-Sheng Qiu:** Writing – review & editing, Supervision, Resources, Project administration, Funding acquisition, Conceptualization. **Yong-Shui Zhou:** Writing – review & editing, Supervision, Resources.

Hua Kang: Writing – review & editing, Supervision, Resources.
Meng-Fei Zhang: Validation, Data curation.

Declaration of competing interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Supplementary data

Supplementary data to this article can be found online at <https://doi.org/10.1016/j.petsci.2026.06.054>.

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