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HYDROCARBON ORIGIN AND PETROLEUM SYSTEM FRAMEWORK OF THE CUU LONG BASIN SHELF (VIETNAM)

This study examines the origin and mechanisms of hydrocarbon accumulation in the Cuu Long Basin (offshore Vietnam), with particular emphasis on oils hosted in fractured and cavernous granitoids of the crystalline basement. A comprehensive set of molecular geochemical analyses was performed, including gas chromatography (GC), gas chromatography–mass spectrometry (GC–MS), and high-performance liquID chromatography (HPLC), in accordance with ASTM and ISO standards. The distribution patterns of n-alkanes, isoprenoids, steranes, and terpanes revealed identical biomarker profiles for basement-hosted oils and oils associated with Oligocene–Miocene reservoirs. The absence of regular $C_{12}$and C_{17} isoprenoids, together with the lack of C_{22} and C_{27} cheilanthanes, as well as elevated cheilanthane indices and high hopane/sterane ratios, confirm the biogenic origin of these oils and indicate a significant bacterial contribution to the initial organic matter. The findings support a two-stage migration model: lateral migration within carrier beds, followed by downward migration along fault and fracture zones into the basement. It is established that hydrocarbons in the crystalline basement occur in secondary accumulations and are derived from Oligocene–Miocene source rocks. These results refine the petroleum system model of the basin and substantiate the priority of future exploration for new accumulations in basement reservoirs.

Keywords: *Cuu Long Basin, crystalline basement, biomarkers, n-alkanes, steranes, terpanes, hydrocarbon migration, petroleum system, offshore Vietnam, basement reservoirs*
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Introduction

The problem of oil occurrence in crystalline basement rocks, particularly when they are closely associated with overlying sedimentary source rock intervals, remains one of the key issues in petroleum geochemistry and basin analysis. The composition of oils and organic matter, together with biomarker distributions at the molecular level, are essential factors for reconstructing hydrocarbon generation conditions and migration pathways [1].

The Cuu Long Basin is among the most prolific petroleum provinces of the Vietnamese continental shelf. One of its most important discoveries is the Bạch Hổ (White Tiger) oil field, where a substantial portion of reserves is hosted in fractured and cavernous granitoids of the crystalline basement, overlain by Oligocene–Miocene sediments. These

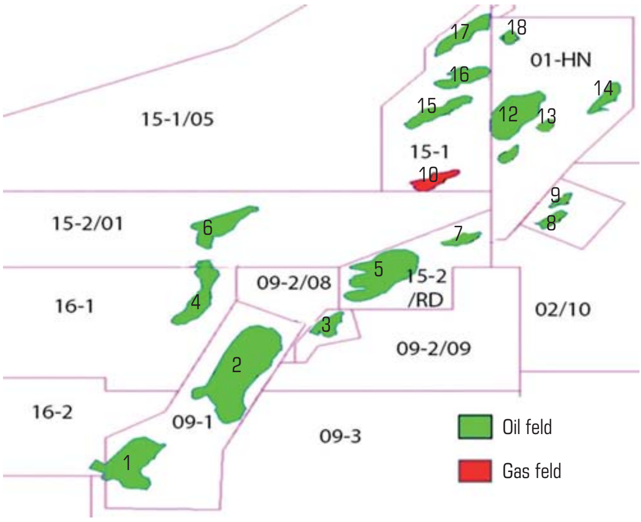

Fig. 1. Distribution of oil and gas fields in the Cuu Long Basin:
1 – Rong (Dragon); 2 – Bach Ho (White Tiger); 3 – Ca Voi Vang (Golden Tuna); 4 – Ca Rong Trang (White Rhino); 5 – Rang Dong; 6 – Ca Heo Den (Black Sea Lion); 7 – Phuong Dong; 8 – Dong Do; 9 – Thang Long; 10 – Su Tu Trang (White Lion); 11 – Emerald; 12 – Ruby; 13 – Pear; 14 – Topaz; 15 – Su Tu Vang (Yellow Lion); 16 – Su Tu Den (Black Lion); 17 – Su Tu Nau (Brown Lion); 18 – Diamond

sediments, comprising both lacustrine and marine deposits, act as the primary source rocks and potential generators of hydrocarbons [2].

Advances in analytical techniques such as gas chromatography (GC), gas chromatography–mass spectrometry (GC–MS), and high-performance liquID chromatography (HPLC) have provided a large body of data on the distribution of n-alkanes, isoprenoids, steranes, and terpanes in oils from both reservoir sandstones and basement reservoirs of the Cuu Long Basin and elsewhere. Such biomarker data make it possible to distinguish between contributions of different types of organic matter, to assess stages of catagenesis, and to reconstruct hydrocarbon migration pathways [3].

Comparisons between oils recovered from the crystalline basement and those from sedimentary reservoirs and source rocks demonstrate a high degree of similarity in their biomarker profiles. This strongly suggests a common genetic origin, linked to the organic matter of the sedimentary cover, dominated by marine phytoplankton with an admixture of benthic algae [3–5].

According to PetroVietnam, 18 oil and gas fields have been discovered in the Cuu Long Basin (**Fig. 1**), of which 15 are currently in production. The Bạch Hổ (White Tiger) field accounts for the largest share of production, with cumulative output of approximately 410 Mt of oil [6]. A unique feature of this field is that most reserves are concentrated within fractured granitoids of Mesozoic age at depths exceeding 3 km, highlighting the high petroleum potential of the crystalline basement. This makes Bạch Hổ an exceptional natural laboratory for testing hypotheses on hydrocarbon origin under such geotectonic conditions [7].

In the global literature, the debate continues along several lines:

1. **Organic origin** — the role of sedimentary organic matter, evaluation of maturity and catagenesis, and the influence of sediment thickness and thermal regimes [8–10].
2. **Abiogenic hypotheses** — suggesting deep-seated (mantle) sources of hydrocarbons, though supported by limited experimental evidence [11].
3. **Migration from source rocks into basement** — considered the most plausible mechanism where fractured and cavernous reservoirs are present and tectonic activity is high [12].
4. **Multifactorial controls** — including tectonics, lithology, porosity, permeability, temperature, and pressure, which collectively determine the potential for hydrocarbon accumulation in basement rocks [13].

The aim of this study is to identify additional molecular-geochemical criteria for the origin of oils from the Bạch Hổ field, in order to further support the hypothesis of their organic derivation.

The specific objectives are as follows:

- to investigate the group composition of oils (saturates, aromatics, resins, asphaltenes);
- to quantify the distribution of n-alkanes, isoprenoids, steranes, and terpanes;
- to evaluate the maturity and catagenetic history of the basin's source rocks;
- to compare the results with global analogues of basement oil accumulations in order to distinguish universal versus local features of petroleum generation.

Research methodology

To achieve the stated objectives, a set of analytical investigations was carried out, including gas chromatography (GC), gas chromatography–mass spectrometry (GC–MS), and high-performance liquID chromatography (HPLC), in accordance with international standards (ASTM D5307, ASTM D7213, ISO 6974) [14–16].

Sample preparation

Crude oil samples were degassed at room temperature and filtered through 0.45 μm membranes. To improve the accuracy of quantitative determinations, internal standards (n-decane for n-alkanes, cholestane for steranes, and 18α(H)-22,29,30-trisnorhopane for terpanes) were added at known concentrations prior to analysis [17].

Analysis of n-alkanes and isoprenoids (GC)

The determination of n-alkanes and isoprenoids was performed by capillary GC using a Bruker instrument equipped with a flame ionization detector (FID).

- Column: fused silica capillary coated with OV-101 phase, 30 m length, 0.25 mm i.d., 0.25 μm film thickness.
- Temperature program: 80 °C, ramped at 4 °C/min to 320 °C, held for 20 min.
- Carrier gas: hydrogen at a constant flow of 1.5 mL/min.
- Peak identification was based on retention times using a C_{10}–C_{44} n-alkane mixture (Supelco, USA) as reference standard.

Gas chromatography–mass spectrometry (GC–MS)

Molecular geochemical analyses were performed using a Hewlett-Packard HP-5975C instrument with a computer data processing system in SIM mode.

- Monitored ions: m/z 71 (n-alkanes, isoprenoids), m/z 177 and 191 (terpanes), m/z 217 (steranes and diasteranes).
- Temperature program: from 40 °C, ramped at 4 °C/min to 290 °C.
- Ionization energy: 70 eV (electron impact).
- Hydrocarbons were separated on the same OV-101 column as in GC analysis.
- Peaks were identified using mass spectra comparison with NIST libraries and specialized biomarker databases (Peters et al., 2005) [1].

Group composition determination (HPLC)

The group composition of oils (saturates, aromatics, resins, and asphaltenes) was determined by HPLC using a Waters instrument with a refractive index detector.

- Column: Energy Analysis (NH_2), 25 cm length, 4.6 mm diameter.
- Eluent: n-hexane, distilled and filtered through 0.5 μm Vullex-SR filters.
- Flow rate: 1.5 mL/min.
- Asphaltenes were precipitated using a 40-fold excess of n-hexane and filtered through 0.5 μm Millex membranes.

Table 1. The n-alkane and isoprenane distribution (based on gas-liquID chromatography) in the Bạch Hổ oil field, well 402

Number of "C" atoms in n-alkane	%	Number of "C" atoms in n-alkane	%
9	6.0	28	2.9
10	8.3	29	2.1
11	7.5	30	1.6
12	6.6	31	1.3
13	6.0	32	1.0
14	5.5	33	0.8
15	5.4	34	0.5
16	4.6	35	0.3
17	4.4	36	0.2
18	3.8	37	0.2
19	3.7	38	0.1
20	3.5	39	0.1
21	3.4	40	0.1
22	3.3	41	< 0.1
23	3.4	42	< 0.1
24	3.0	43	< 0.1
25	2.9	44	< 0.1
26	2.8	pristane	1.4
27	2.9	phytane	0.6

Table 2. Geochemical characteristics (based on gas-liquID chromatography) of the oil of the Bạch Hổ field (well 402) based on normal alkanes and isoprenanes

$\frac{Pristan}{Phytane}$	$\frac{Pristan}{H-C_{17}}$	$\frac{Phytane}{H-C_{18}}$	$\frac{Pristan+Phytane}{H-C_{17}+H-C_{18}}$	$\frac{H-C_{25}+H-C_{27}}{2_H-C_{26}}$
2.27	0.31	0.16	0.24	1.06

Table 3. The regular isoprenane (C_{11}-C_{20}) distribution (based on gas-liquID chromatography) in the oil of the Bạch Hổ field (well 402)

Number of "C" atoms in regular isoprene	%
11	17.2
13	12.7
14	12.8
15	10.2
16	15.9
18	8.3
19 (pristane)	15.9
20 (phytane)	7.0
Note: Regular isoprenanes of C_{12} and C_{17} composition are absent	

- The content of fractions was expressed as mass percent of the initial sample.

Data quality and processing. All measurements were performed in triplicate; reproducibility for key biomarker ratios (Pr/Ph, $C_{31}H/C_{29}H$, ΣC_{27}–C_{29} steranes) was within ±5 %. Statistical treatment included principal component analysis (PCA) and correlation analysis to identify similarities and differences between samples from various depths and stratigraphic complexes [18].

Results

Geochemical characteristics of n-alkanes and isoprenoids According to GC data (**Table 1**, **Fig. 2**), the oil from well 402 exhibits a unimodal distribution of n-alkanes ranging from C_{19} to C_{44}, with dominant fractions in the C_{17}–C_{33} range and local maxima at C_{23}, C_{27}, and C_{28} [19, 20]. This distribution pattern is typical of oils generated from marine source rocks rich in phytoplankton-derived organic matter. Unimodal curves are generally interpreted as evidence of a single oil generation pulse and a high degree of mixing within the reservoir trap.

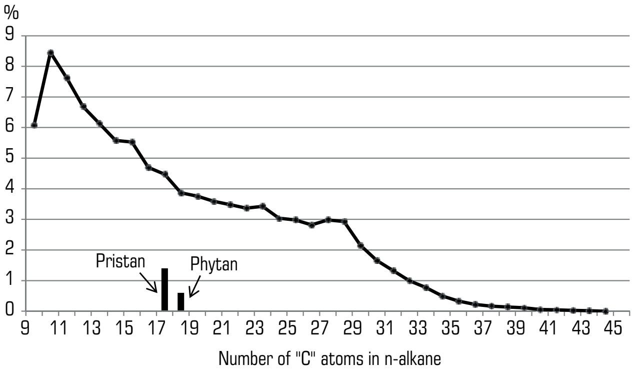

Fig. 2. The n-alkane and isoprenane distribution (based on gas-liquID chromatography) in the oil of the Bạch Hổ field (well 402)

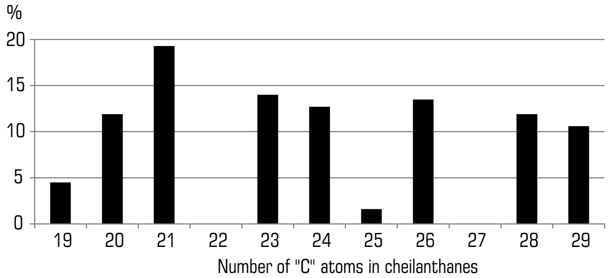

Fig. 3. The distribution (based on gas-liquID chromatography) of cheilanthanes C_{19}-C_{29} in the oil of the Bạch Hổ field (well 402)

The odd-over-even predominance coefficient $\frac{H-C25+H-C27}{2H-C26}$ (**Table 2**) is slightly greater than 1, indicating a minimal contribution of terrestrial organic matter and confirming the dominance of marine organic input [21]. This parameter is an important tool for regional oil–oil correlation: oils with low odd-over-even predominance are typically characteristic of lacustrine basins (e.g., North China, East Africa), whereas values above unity are more common in marine depositional settings.

Analysis of the distribution of isoprenoids C_{11}–C_{20} (**Table 3**, **Fig. 3**) revealed the absence of C_{12} and C_{17} homologues, which is a diagnostic indicator of the biogenic origin of the oil [22]. Isoprenoids are derived from phytol, the side chain of chlorophyll, and their distribution reflects the type of original organic matter and the prevailing diagenetic conditions. The high pristane/phytane ratio (Pr/Ph = 2.27) indicates an oxic depositional environment and moderately shallow marine conditions. Such values are characteristic of nearshore marine settings and rule out models of deposition in a deep, reducing basin.

Sterane–terpane complex

Steranes and terpanes are among the most informative biomarkers for reconstructing the composition of the original biomass and the thermal history of a basin. GC–MS results (**Tables 4 and 5**) revealed high concentrations of C_{19}–C_{29} tricyclic terpanes, with a cheilanthane index of 75.4 (**Fig. 4**), indicative of a significant bacterial contribution [23]. This suggests that the original organic matter was deposited under conditions favorable for the development of bacterial communities — typically in shallow marine shelf settings characterized by periodic water column stratification and active organic matter degradation.

The neoadiantane ratio ($NeoG_{29}/G_{29}$) of 1.0 and the elevated G_{30}/C_{29}-sterane ratio (6.87) indicate moderate thermal maturity and an actively biodegraded or microbially processed source of organic matter [24, 25].

Table 4. Geochemical characteristics (based on gas-liquID chromatography) of the Bạch Hổ field oil (well 402) based on steranes

Regular steranes			Maturity s C_{29}		Steranes C_{27}
C_{27}/C_{29}	C_{28}/C_{29}	$C_{27}:C_{28}:C_{29}$	$C^{1}_{maturity}$	$C^{2}_{maturity}$	diasteranes / regular steranes
0.92	0.68	35:26:39	0.56	0.78	0.37

Table 5. Geochemical characteristics (based on gas-liquID chromatography) of the Bạch Hổ field oil (well 402) based on terpanes

Ts/Tm	H_{29}/H_{30}	M/H_{30}	$H_{27}: H_{29}: H_{30}: H_{31}$	Three / Penta	Tetra / Three	$NeoH_{29}/H_{29}$	H_{30}/Sterane C_{29}
2.1	0.67	0.11	27:23:36:14	0.84	0.40	1.0	6.87

Table 7. The group composition (based on high-performance liquID chromatography) of the White Tiger field oil (well 402)

Compound	%
Paraffins-cyclo-paraffins (saturated HC)	77.0
Mono-aromatic HC	8.6
Bi-aromatic HC	4.4
Tri-/poly-aromatic HC	1.4
Resins	6.6
Asphaltenes	2.0

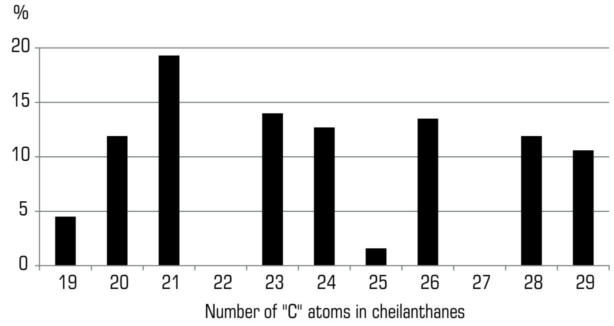

Fig. 4. The distribution (based on gas-liquID chromatography) of cheilanthanes C_{19}-C_{29} in the oil of the B ch H field (well 402)

Table 6. The distribution (based on gas-liquID chromatography) of cheilanthanes (tri-cyclical terpanes) C_{19}-C_{29} in the oil of the Bạch Hổ field (well 402)

Number of "C" atoms in cheilanthanes	Cheilanthanes (stereochemical indication)*	%
19	13β	4.5
20	13β, 14α	11.9
21	13β, 14α	19.3
23	13β, 14α	14.0
24	13β, 14α	12.7
25	13β, 14α	1.6
26	13β, 14α; 22S+22R	13.5
28	13β, 14α; 22S+22R	11.9
29	13β, 14α; 22S+22R	10.6
Note: The cheilanthanes of C_{22} and C_{27} composition are absent. *The orientation (H) is shown everywhere		

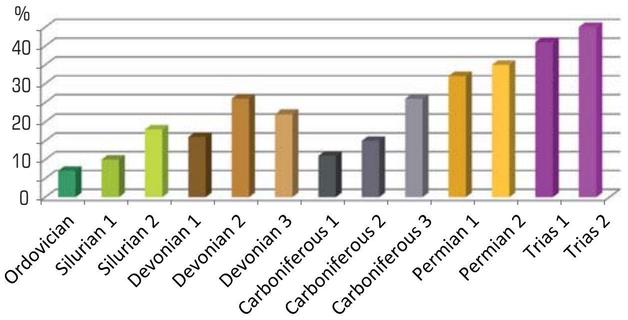

Fig. 5. The cheilanthane contents (cheilanthane index) in oils depending on the age of the host sediments (average values) [3, 9]

Similar values have been reported in oils from the Gulf of Mexico and the Indian offshore, allowing the Cuu Long Basin to be considered a representative example of shelf-type petroleum systems.

Cheilanthane distribution

Tricyclic terpanes (**Table 6**, Fig. 4) show the absence of C_{22} and C_{27} homologues, which is interpreted as a result of biosynthetic constraints (**Fig. 5**). The cheilanthane index decreases with depth in the stratigraphic section, reflecting a lower relative contribution of bacterial organic matter at greater levels of hydrocarbon generation. A similar trend (decreasing bacterial markers with depth) has been documented in sedimentary basins of Western Siberia and the North Sea [26].

Group composition of oil

According to HPLC results (**Table 7**), the oil contains more than 60% saturated hydrocarbons, classifying it as a "light" and technologically valuable crude. The low concentrations of resins and asphaltenes indicate the absence of significant oxidation and biodegradation processes, indirectly confirming timely migration and rapID accumulation of oil in the reservoir. Comparison with oils from the shelves of China and India shows similar values, supporting the common genetic models proposed for rift-related basins of Southeast Asia [27].

Cheilanthanes are traditionally considered to form either as products of microbial lipID transformation or via thermocatalytic processes at high maturity levels. Our analysis demonstrates a consistent decrease in their relative concentration with increasing depth and temperature across the basin section (from Triassic to Ordovician). This trend is inconsistent with classical thermocatalytic models, which predict increasing concentrations with advancing catagenesis. Based on these observations, we infer that the predominant pathway of cheilanthane formation in the Bạch Hổ oils was microbial. Furthermore, the cheilanthane index indicates that the oil is younger than Triassic in age (see Fig. 5).

Discussion of results

Analysis of C_{27}–C_{29} sterane profiles (**Fig. 6 *a, b***) revealed nearly identical relative abundances of these compounds in basement-hosted oils and in oils genetically linked to Oligocene–Miocene source rocks, indicating a common genetic origin. This confirms that hydrocarbons were generated from the same source rock system under comparable catagenetic conditions. The results also suggest that the oil has not undergone significant secondary biodegradation or thermal alteration, as evidenced by the normal sterane distributions and the preservation of isoprenoID profiles (**Fig. 6 *c, d***).

The pristane/phytane ratio (Pr/Ph < 3) corresponds to depositional environments ranging from mildly oxic to mildly reducing, which are typical of lagoonal and nearshore marine facies [9]. These findings are in good agreement with geochemical maturity modeling of the basin's source rocks and paleoenvironmental reconstructions performed for Southeast Asian rift basins [19, 20].

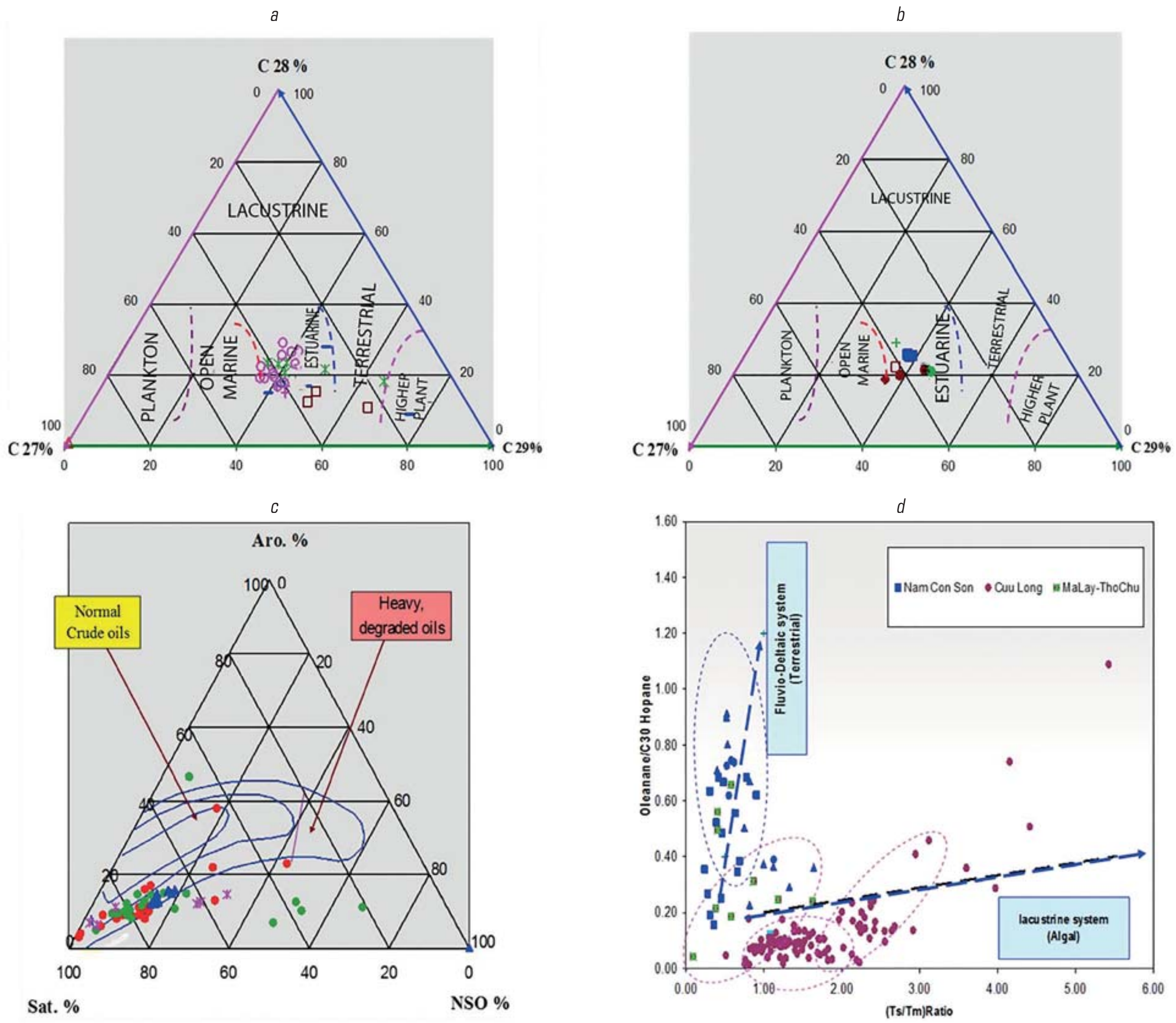

Fig. 6. Ternary diagram of C_{27}–C_{29} sterane distribution:
a – source rock samples; *b* – oil samples; *c* – C_{15}^{+} hydrocarbon fraction composition of oils from the Cuu Long Basin; *d* – oil origin comparison for three basins: Cuu Long, Nam Con Son, and Malay–Tho Chu

Discussion on Basement Oil Genesis

The discovery of numerous accumulations in granitoids of the crystalline basement has stimulated a long-standing debate regarding the nature of these occurrences. Some researchers [28–29] have proposed an abiogenic origin of hydrocarbons, suggesting their migration from the mantle or from deep-seated fluID systems. However, detailed biomarker analyses — including distributions of isoprenoids and tricyclic terpanes (see Tables 2, 6; Figs. 3, 5, 6) — provide strong evidence for the organic origin of basement-hosted oils. The molecular geochemical characteristics of the Bạch Hổ oils are virtually identical to those of oils from Oligocene–Miocene sedimentary reservoirs [30–31].

Key biomarker features — the absence of C_{12} and C_{17} isoprenoids, absence of C_{22} and C_{27} cheilanthanes, a high cheilanthane index, and elevated neoadiantane/adiantane ratios — indicate a significant bacterial contribution to the original organic matter [23–26]. Similar biomarker signatures are observed in oils from the North Sea and the Gulf of Mexico, allowing the Cuu Long Basin to be classified as a typical basement-involved petroleum system.

Migration Processes and Accumulation Mechanisms

The subsurface of the Cuu Long Basin is characterized by a layered-block structure, which governs a complex hydrocarbon migration regime. Accumulation occurred in two main stages:

1. **Lateral migration** from Oligocene–Miocene source rocks through permeable carrier beds and lithologic traps.
2. **Subvertical interformational migration** along faults, fracture zones, and stratigraphic unconformities, synchronous with paleo- and neotectonic activation [10].

During tectonically quiescent periods, diffusive fluID discharge prevailed through low-permeability formations, whereas during tectonic reactivation, pressured fluID systems caused focused expulsion, forming inter- and intraformational accumulations. In the crystalline basement, the dominant mechanism was downward migration, driven by the decrease of hydrodynamic potential with depth and facilitated by networks of open fractures. The most favorable sites for hydrocarbon accumulation are located at the contacts between the sedimentary cover and basement granitoids, where contrasts in reservoir and sealing properties create natural migration pathways.

GeofluID Dynamic Aspects

Modern geofluID dynamic concepts also consider the influence of electrical fields generated during faulting and fracturing. During tectonic activation, high-voltage electrical fields can develop due to the piezoelectric effect in crystalline rocks, enhancing directed hydrocarbon filtration into the basement [11]. This mechanism explains the formation of secondary oil accumulations and emphasizes the role of the basement as a reservoir rather than a hydrocarbon generation source.

Scientific and Practical Implications

- Biomarker evidence confirms the biogenic origin of basement oils and excludes a mantle-derived genesis.
- Downward migration through faults and fracture systems is the primary mechanism of basement trap filling.
- High cheilanthane indices and elevated G_{30}/C_{29}-sterane ratios can serve as effective exploration criteria for predicting new basement accumulations.
- The results of this study substantiate that the crystalline basement of the Cuu Long Basin should remain a priority target for future exploration and appraisal drilling.

Conclusions

A comprehensive molecular geochemical study of oils from the Bạch Hổ (White Tiger) field and other accumulations in the Cuu Long Basin has led to the following findings:

- The biomarker profiles (n-alkanes, isoprenoids, steranes, and terpanes) of basement-hosted oils are identical to those of oils from Oligocene–Miocene sedimentary reservoirs, confirming a common hydrocarbon generation source.
- The absence of regular C_{12} and C_{17} isoprenoids, as well as C_{22} and C_{27} cheilanthanes, provides strong evidence for the biogenic origin of the oils and indicates normal biochemical pathways of hydrocarbon formation.
- Elevated cheilanthane indices, neoadiantane ratios, and high hopane/sterane ratios indicate a significant bacterial contribution to the original organic matter, typical of coastal-marine source rock settings.
- The group composition of the oils, with >60% saturated hydrocarbons and low resin and asphaltene contents, reflects their high quality and the absence of significant secondary degradation.

In summary, hydrocarbon accumulations in the granitoids of the Cuu Long Basin crystalline basement represent secondary accumulations, with Oligocene–Miocene source rocks serving as the primary generators.

Practical significance:

- The results refine the petroleum system model of the basin.
- They provide a basis for predicting new basement traps and accumulations at the sediment–basement interface.
- They can be used to define priority directions for exploration and appraisal drilling in the offshore areas of southern Vietnam.

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