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MOLECULAR FEATURES OF OILS FROM THE EMBA REGION (PRECASPIAN BASIN): ORIGIN, THERMAL MATURITY, AND GENETIC CORRELATION

Abstract

The Precaspian Basin, including its southeastern part, represents a unique oil and gas province with giant fields such as Tengiz and Kashagan, whose reserves are estimated in billions of tons. Despite extensive research in the region, questions regarding the genetic affiliation of oils and their paleoformation conditions require additional geochemical analyses of oil samples. To conduct a comprehensive geochemical characterization and genetic correlation of oils from the Emba region, with a focus on molecular marker analysis to reconstruct oil formation conditions seven oil samples were taken from various stratigraphic horizons. The study employed advanced analytical techniques gas chromatography (Agilent 7890B) for detailed analysis of n-alkanes and isoprenoids (pristane and phytane) and gas chromatography-mass spectrometry in selected ion monitoring mode m/z 191, 217 for terpane and sterane identification, respectively. Particular emphasis was placed on the computation of essential geochemical indices isoprenoid, hopane, and sterane isomerization ratios along with the generation of diagnostic plots. The results indicate a marine origin of the studied oils with dominant carbonate source rocks (C_{27} steranes > 30%, C_{29}/C_{30} hopanes > 1). Pr/Ph ratios (0.79–1.07) and elevated C_{35} homohopanes suggest formation under reducing conditions. Thermal maturity parameters (Ts/(Ts+Tm) = 0.15–0.64; C_{29} $\beta\beta/(\alpha\alpha+\beta\beta)$ = 0.55–0.71) confirm that the samples were generated during the oil window. Genetic correlation grouped all samples into a single oil family of marine carbonate origin. The findings are practically significant for predicting analogous accumulations in the region.

Keywords: Precaspian Basin, oil geochemistry, GC-MS, biomarkers, thermal maturity, source rocks, reducing conditions, marine environment, genetic correlation.

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Introduction

The Precaspian Basin is one of the most promising petroleum provinces on the East European Platform, characterized by a thick sedimentary cover and significant hydrocarbon resources (Figure 1a). It contains most Kazakhstan's discovered fields, including unique giant accumulations such as Tengiz, Karachaganak, Kashagan, and Zhanazhol [1]. Classified in the highest resource potential group with forecasted reserves exceeding 10 billion tons, the basin holds strategic importance for Kazakhstan's oil and gas industry. Structurally, the Precaspian Depression is divided into several blocks, including the Northern, Central, Northwestern, Eastern, and Southern zones, each with distinct geological features (Figure 1b) [2]. The southeastern part of the basin, particularly the Emba region hosting the studied field X, exhibits high prospectivity in both sub-salt and supra-salt complexes [3].

Field X is associated with a salt-dome structure, with productive intervals in the Jurassic, and Triassic deposits. Reservoirs are represented by argillaceous-carbonate rocks with porosity of 16–21% and permeability of 0.016–0.030 D. The oil-bearing Jurassic strata (3–10 m thick) are characterized by oil saturation coefficients of 0.5–0.8, gas saturation of 0.5–0.8, and a gas-oil ratio of 28–180 m^3/m^3. Initial reservoir conditions range from 23–29 MPa at temperatures of 74–97°C [2].

The geochemical properties of oils and source rocks in the Emba region have been the subject of numerous studies elucidating their genesis, formation conditions, and maturity. Recent works confirm the prevalence of marine carbonate organic matter (OM) sources formed under reducing conditions [4–12]. For instance, research by T. Jarassova and M. Altunsoy (2021) revealed that extracted hydrocarbons from the central part of the province are characterized by low Pr/Ph ratios (<1) and high C_{35}/C_{31-35} homohopane indices, typical of anoxic carbonate settings, and maturity parameters $Ts/(Ts+Tm) = 0.15–0.64$ and $C_{29}\ \beta\beta/(\beta\beta+\alpha\alpha) = 0.57–0.71$, corresponding to the main oil window [4]. T.Jarassova and M.Altunsoy (2024, 2025) analyzed four (# 1, 2, 42 and 55) and five (# 11, 17, 20, 44 and 48) crude oil samples from the south-eastern Precaspian Basin were analyzed using gas chromatography-mass spectrometry (GC-MS) to assess their biomarker composition and concluded that oils originated from carbonate-dominated source rocks that have reached a late-mature stage within the peak oil window [5–6]. Seitkhaziev E.Sh. et. al. (2019, 2020) expanded these data by analyzing 15 fields in the southern Precaspian, where the distribution of tricyclic terpanes and steranes confirmed a marine OM origin; based on Tmax (438–464°C) and R_0 (0.8–1.1%), oils were categorized into groups such as early maturity (Karasor, Dosmukhambetovskoye fields), peak maturity (S. Nurzhanov, Zapadnoye Prorva), and late maturity (Tengiz, Kashagan, Karaton) [7–10]. Carbon isotope analysis ($\delta^{13}C$) indicated a Paleozoic age for the source strata. Detailed analysis of the catagenetic transformation of Paleozoic and Mesozoic OM was performed by Nursultanova S.N. et al. (2019) [11]. A study of 30 samples from the Tolky, Saetobe, and Bekbulat fields using pyrolysis (Rock-Eval) and GC-MS showed the highest generative potential (S_2 up to 22 mg HC/g rock) for carbonate marls of the Asselian stage (Type I–II OM); clay rocks of Visean-Serpukhovian age (Type III OM) have low HI values (<160 mg HC/g TOC) but are significant for gas generation, highlighting the role of the South-Emba Paleo-depression as a hydrocarbon migration source for giant fields (Tengiz, Kashagan). T.Jarassova et.al. (2025) conducted a similar study of oil from the Alibekmola field and, using biomarker ratios, determined the carbonate lithology of the oil source strata, the early stage of hydrocarbon generation, and established the possible direction of oil migration based on the 4MDBT/1MDBT and methylphenanthrenes indices [12].

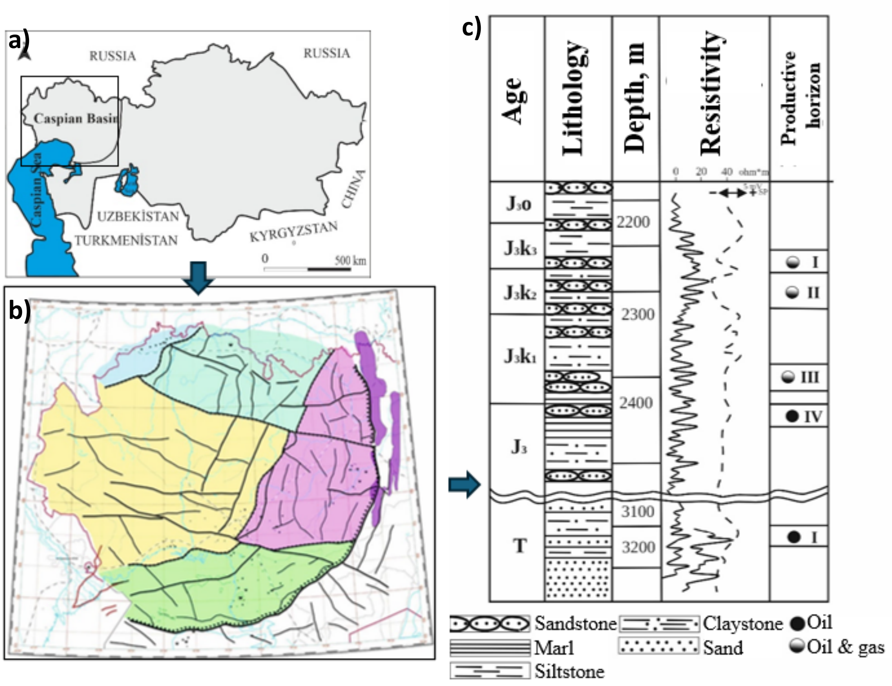

Figure 1 – Overview map: a) map of Kazakhstan, b) Precaspian Basin, c) Cross-section of the productive part of the deposits [modified from 1, 2, 4]

This paper presents new data on seven oil samples analyzed by GC and GC-MS (ions m/z 191, 217) for identification of n-alkanes and isoprenoids (Pr, Ph) as indicators of facies conditions, and terpanes (Ts, Tm) and steranes as maturity markers. The study aims to refine the genetic classification of oils from the Emba region and perform genetic correlation of oil samples based on geochemical data.

Materials and methods

Seven crude oil samples were collected from study area. Reservoir properties are represented by clastic rocks with porosity of 16–21% and permeability of 0.016–0.030 D (Figure 1c). Oil density in the studied samples ranges from 736–775 kg/m³, reservoir oil viscosity is 0.84–0.96 mPa·s, and gas content is 109–150 m³/t.

The selected oil samples from Field X in the southeastern Precaspian basin were analyzed using gas chromatography (GC) and gas chromatography-mass spectrometry (GC-MS) (Figure 2) to assess n-alkane and isoprenoid composition and their biomarker signatures, respectively. The geochemical analysis methodology involved sample vaporization in a gas chromatograph equipped with a capillary column, component separation using helium as carrier gas, followed by ionization of eluted compounds in the mass spectrometer via electron impact and separation by mass-to-charge ratio for molecular identification. During sample preparation, hydrocarbon samples were separated into saturated and aromatic fractions via column chromatography using alumina and silica gel as sorbents. Elution was performed with pentane (saturated fraction) and dichloromethane (aromatic fraction) [12–14].

Geochemical investigations were performed on an Agilent 7890B gas chromatograph with a mass-selective detector in selected ion monitoring (SIM) mode, enabling targeted analysis for specific ions such as n-alkanes and isoprenoids, terpanes (m/z 191), and steranes (m/z 217) [13]. The obtained chromatographic data provided diagnostic information on hydrocarbon origin, depositional conditions, and thermal maturity [14].

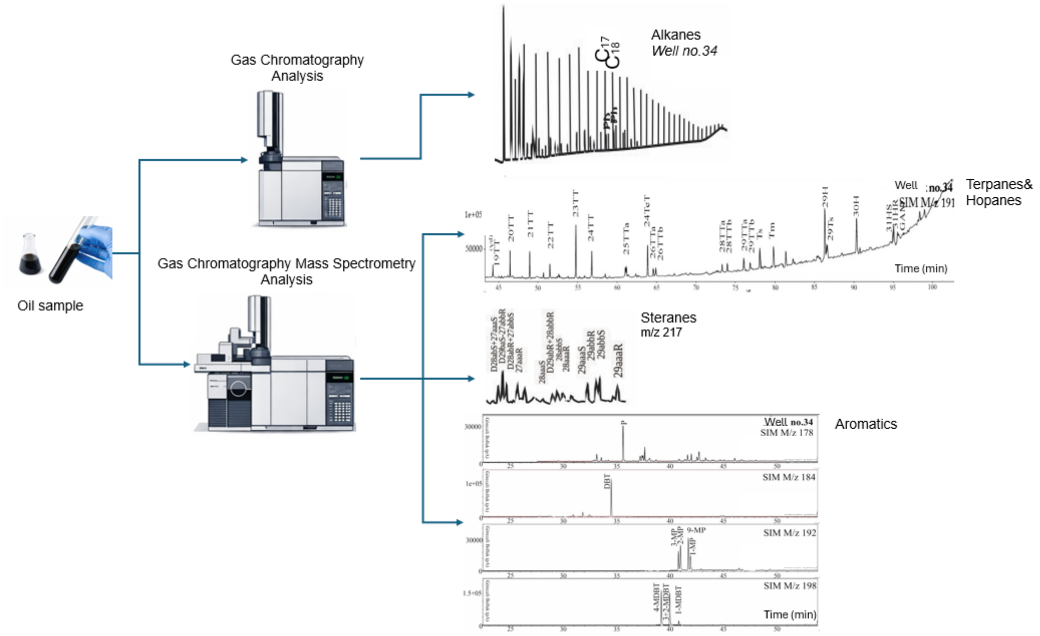

Figure 2 – Gas chromatography (GC) and gas chromatography-mass spectrometry (GC-MS) analysis

Results and discussion

For the seven oil samples from different wells of Field X, gas chromatograms of n-alkanes and isoprenoids were obtained. Based on gas chromatography data, the following ratios were determined: Pr/Ph (pristane/phytane), Pr/C_{17}, Ph/C_{18}, Carbon Preference Index (CPI) (Table 1).

Table 1 – Results of geochemical analyses

Well #	34	42	43	47	49	50	51
Age	*T-IV*	*K1v*	*T-V*	*J-II*	*J-II*	*J-II*	*J-II*
Pr/Ph	0.97	0.79	0.80	0.93	1.07	1.05	0.99
Pr/C_{17}	0.44	0.38	0.39	0.44	0.42	0.42	0.45
Ph/C_{18}	0.50	0.60	0.54	0.50	0.45	0.45	0.48
CPI[1]	1.05	0.92	0.93	1.01	0.93	1.00	0.91
OEP[2]	0.94	1.00	1.00	0.98	0.99	1.00	0.99
TAR[3]	0.70	0.11	0.37	0.31	0.20	0.21	0.25
K_i	0.47	0.47	0.46	0.47	0.43	0.43	0.47
$C_{17}/C_{17}+C_{27}$	0.83	0.87	0.83	0.87	0.83	0.87	0.83
$C_{18}/C_{18}+C_{28}$	0,50	0,59	0,50	0,59	0,50	0,59	0.50
T_s/T_m	0,94	0,18	0,99	0,57	0,8	1,76	0.48
Ts/(Ts + Tm)	0.48	0.15	0.5	0.37	0.44	0.64	0.32
T_{s29}/T_{m29}	0.31	0.12	0.41	0.27	0.25	0.26	0.24
Moretane/C_{30} hopane	0.61	-	-	-	-	-	-
C_{29} / C_{30} H	1.15	-	-	-	-	-	-
C_{27}, %	32	37	31	40	35	36	35
C_{28},%	22	22	22	23	23	24	23
C_{29}, %	46	41	47	37	42	40	43
C_{29}/C_{27}	1.34	1.10	1.52	0.94	1.20	1.12	1.23
C_{29} 20S/ 20S+20R, %	-	-	55	-	59	100	58
C_{29} ββ /(αα + ββ), %	-	-	60	-	60	68	57

1 CPI=½[(C25+C27+C29+C31+C33/C24+C26+C28+C30+C32)+(C25+C27+C29+C31+C33/C26+C28+C30+ C32+C34)]
2 OEP= (C21+6C23+C25)/(4C22+4C24)
3 TAR = (C27 + C29 + C31) / (C15 + C17 + C19)

n-Alkanes

n-Alkanes are saturated linear hydrocarbons used in geochemistry to determine organic matter origin and depositional conditions. The absence of an unresolved complex mixture (hump) in the n-alkane distribution on chromatograms and their bimodal distribution indicate that the studied samples have not undergone significant biodegradation (Figure 2, alkanes). In all oil samples, short-chain n-alkanes ($<C_{20}$) predominate, suggesting an origin from algae and microorganisms and indicating a marine source [15].

The ratio of the sum of odd-numbered n-alkanes to even-numbered n-alkanes is termed the Carbon Preference Index (CPI), used to assess the thermal maturity of organic matter and the type of original OM. All oils show similar n-alkane chromatograms, with CPI values ranging from 0.91 to 1.05 (Table 1). For samples No. 34, 47, and 50, CPI exceeds 1.0, indicating a predominance of odd n-alkanes. For all other oil samples, CPI values are less than 1.0, indicating a predominance of even n-alkanes and suggesting relatively low thermal maturity. A low CPI close to 1.0 shows that the analyzed oils originate from a marine source rock and contain insignificant amounts of terrestrial organic matter [15, 16]. The Odd-Even Predominance (OEP) value for samples No. 42, 43, and 50 is 1.0, indicating thermal maturity. Oil samples with CPI or OEP values below 1.0 suggest an origin from carbonate source rocks or formation in a hypersaline environment with comparatively low maturity.

OEP values (0.94–1.0), like CPI values, yield analogous results (Table 1). On the OEP-CPI diagram, the samples indicate maturity (Figure 3) [17]. The CPI vs. Pr/Ph diagram shows that samples No. 34, 47, and 50 were deposited in a marine environment, while other samples originate from carbonate or evaporitic source rocks in a saline setting (Figure 4) [15, 18].

Certain n-alkane ratios can be used to determine variations in terrestrial and marine hydrocarbon contributions in sediments or rock extracts. For example, higher Terrigenous/Aquatic Ratio (TAR) values in various rocks indicate greater terrestrial input into the basin compared to aquatic sources [19]. In the studied samples, TAR varies from 0.11 to 0.70, indicating a marine source.

Isoprenoids

Pristane (Pr) (2,6,10,14-tetramethylpentadecane) and phytane (Ph) (2,6,10,14-tetramethylhexadecane) are the most common isoprenoid compounds. The Pr/Ph ratio is a widely used geochemical parameter reflecting depositional environment conditions, organic matter type, and environmental character [15]. In the studied samples, the Pr/Ph ratio ranges from 0.79 to 1.07, indicating a predominance of hypersaline or carbonate conditions with a reducing environment during oil accumulation [20–23]. Isoprenoid values also suggest that organic matter was deposited under reducing conditions (with or without sulfur) (Figure 5).

In the studied samples, the Pr/C_{17} ratio is 0.38–0.45, and the Ph/C_{18} ratio ranges from 0.45 to 0.60. Low values (<1) of Pr/C_{17} and Ph/C_{18} (Table 1) are indicators of high thermal maturity. The relationship between Pr/C_{17} and Ph/C_{18} ratios agrees with low Pr/Ph values and confirms that the analyzed oils are derived from a source rock containing marine organic matter (Type II kerogen) deposited under reducing conditions according to the Connan-Cassou diagram (Figure 6) [15, 24–26].

With increasing temperature, isoprenoids degrade more readily than n-alkanes. The ratio of the sum of isoprenoid concentrations to n-alkanes with similar chromatographic retention times, $(Pr + Ph)/(C_{17} + C_{18}) = K_i$ (isoprenoid coefficient), allows estimation of maximum temperatures during oil formation. For the studied oil samples, the isoprenoid coefficient ranges from 0.43 to 0.47, indicating oil formation at relatively high temperatures (Table 1).

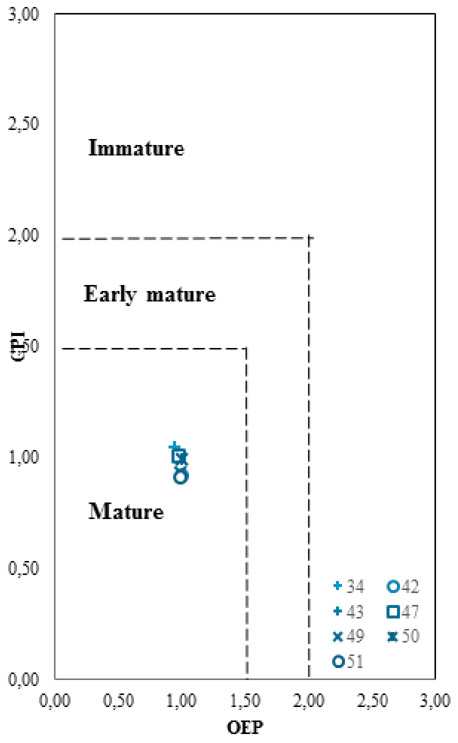

Figure 3 – Maturation level according to the 36th OEP-CPI diagram [modified from Adedosu 17]

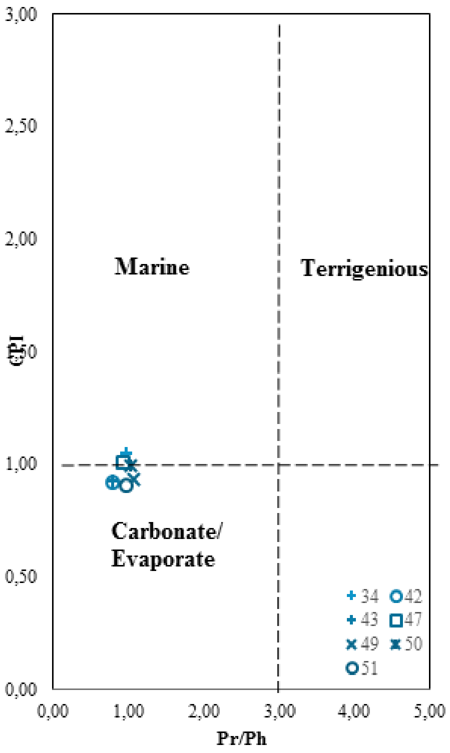

Figure 4 – Normal alkane and isoprenoid ratios depending on the source [modified from 15]

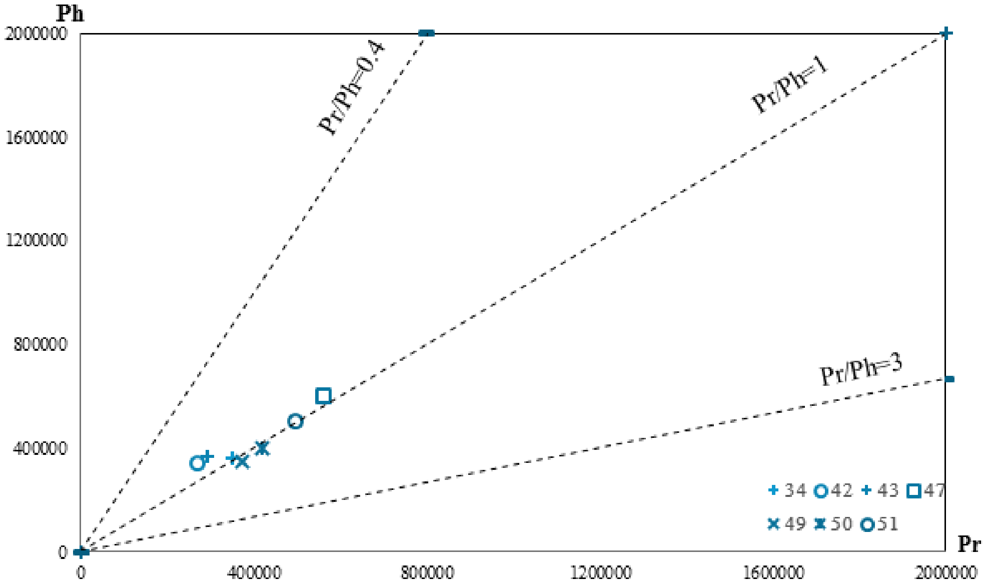

Figure 5 – Precipitation conditions according to the Pr-Ph diagram [modified from 22]

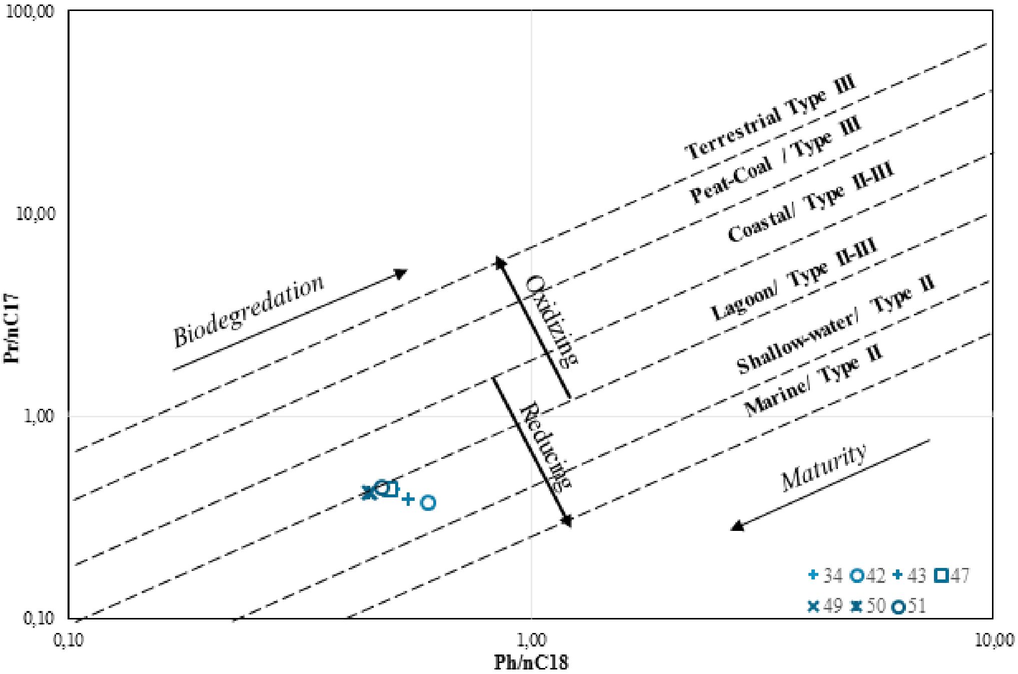

Figure 6 – Depositional environmental characteristics and organic matter types
of the samples examined in the Pr/C17-Ph/C18 diagram [modified from 26]

Terpanes

Terpanes are polycyclic saturated hydrocarbons (biomarkers) including tri-, tetra-, and pentacyclic structures (e.g., hopanes), used to determine depositional conditions, thermal maturity, and organic matter origin (Figure 8). One parameter defining thermal maturity is the moretane/C_{30}-hopane ratio, $T_s/(T_s+T_m)$ or T_s/T_m. 17α(H)-22,29,30-trisnorthopane (Ts) is less stable than 18α(H)-22,29,30-trisnorneohopane (Tm) during thermal maturation [27]; the Ts/Tm ratio depends on the source material [28]. In the studied samples, the Ts/Tm ratio varies from 0.18 to 1.76. In sample No. 50, the Ts/Tm ratio exceeds 1, indicating late maturity, whereas in sample No. 42 the T_s/T_m

ratio is 0.18, suggesting an immature source rock. In other oil samples, Tm predominates over Ts, characteristic of early-mature source rocks (Table 1). The Ts_{29}/Tm_{29} ratio corresponds to mature to late-mature source rocks (Figure 7).

The Ts/(Ts+Tm) ratio depends on maturity degree and source rock lithology (Peters and Moldowan, 1993). The stability of Tm during catagenesis is lower compared to Ts, so the Ts/(Ts+Tm) ratio can reflect varying source rock maturity. Furthermore, this ratio is influenced by the mineralogical composition of the source rock. High Ts/(Ts+Tm) values are associated with the presence of clay minerals, whereas carbonate source rocks are characterized by lower values [29]. In this study, Ts/(Ts+Tm)values range from 0.15 to 0.64 (Table 1). In sample No. 42, the Ts/(Ts+Tm) ratio is 0.15, indicating an early-mature source rock. In other samples, Ts/(Ts+Tm) values exceed or are near 0.5, corresponding to the main oil window (Figure 8).

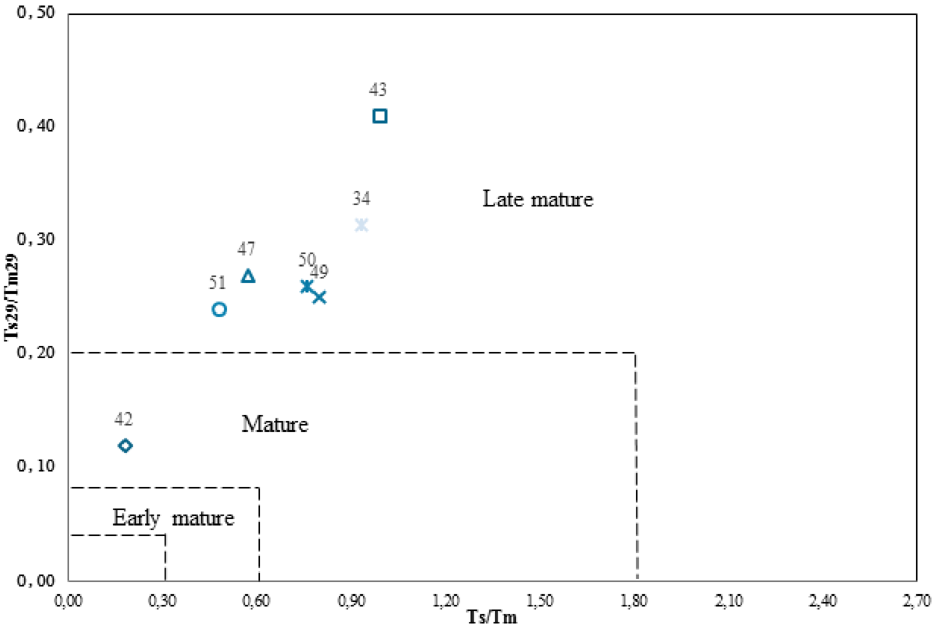

Figure 7 – Ts29/Tm29 - Ts/Tm diagram showing the degree of maturation of the samples [modified from 15]

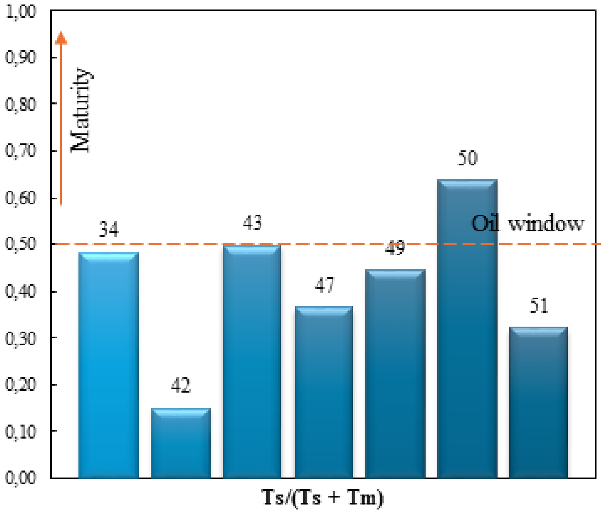

Figure 8 – Distribution of the Ts/(Tm+Ts) parameter in oil samples [modified from 15]

17β,21α(H)-moretanes are less stable than 17α,21β(H)-hopanes, and their content decreases with thermal maturation. Moretane and C_{30} hopane peaks are present only in the mass chromatogram of sample No. 34, and the moretane/C_{30} hopane ratio is 0.61, corresponding to a mature source rock [30, 31].

High values of 30-norhopane/hopane are typical for oils generated in anoxic carbonate or marly rocks. A C_{29}/C_{30} hopane ratio > 1.0 also indicates such conditions [32, 33]. In this work, C_{29}/C_{30} hopane = 1.15 (sample No. 34), and the dominance of C_{29}-norhopane is associated with organic facies enriched in carbonates.

Steranes

Steranes are polycyclic hydrocarbon biomarkers used to determine organic matter type (marine/terrestrial), the age of source rocks, and oil maturity (Figure 9). Concentrations of C_{27}, C_{28}, and C_{29} steranes are used to characterize source rock depositional environments. The distribution of oil samples is shown on a C_{27}–C_{28}–C_{29} triangular diagram (Figure 12). All oil samples show sterane profiles with relatively high contents of C_{27} and C_{29} steranes, which predominate in marine organisms and terrestrial plants, respectively [34, 35]. According to the C_{27}:C_{28}:C_{29} sterane distribution, sample No. 47 was deposited in an open marine setting, while other samples are from estuarine or bay environments [36–38]. The C_{29}/C_{27} sterane ratio ranges from 0.93 to 1.51 (Table 1). The predominance of C_{29} steranes suggests a contribution from terrestrial higher plants. In sample No. 47, the C_{29}/C_{27} sterane ratio is less than 1, whereas in other samples $C_{27} < C_{29}$, indicating an origin from kerogen with a predominance of higher plant material.

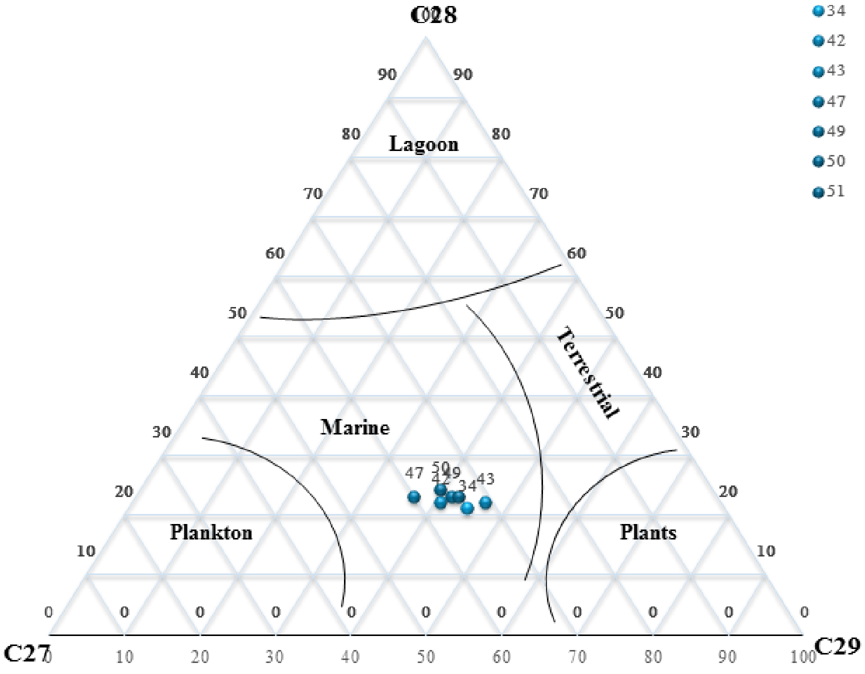

Figure 9 – Triangular diagram showing the relationship between depositional environment and the sterane (C27, C28, C29) composition of organic matter [modified from 36]

C_{29} Sterane Isomerization Ratio 20S/(20S+20R)

Upon reaching maximum thermal maturity in oil generation, the C_{29} 20S/(20S+20R) sterane ratio attains an equilibrium value of 0.55, indicating the maturity of the studied samples (Table 1) [15, 39]. The C_{29} ββ/(αα+ββ) ratio reaches equilibrium at 0.7; in the studied samples, this parameter varies from 0.55 to 0.60.

Plots of C_{29} 20S/(20S+20R) and C_{29} ββ/(αα+ββ) sterane ratios are particularly effective tools for determining the thermal maturity of source rocks and oils [40, 41]. According to the C_{29} sterane isomer plot, the oil samples are generally mature (Figure 10).

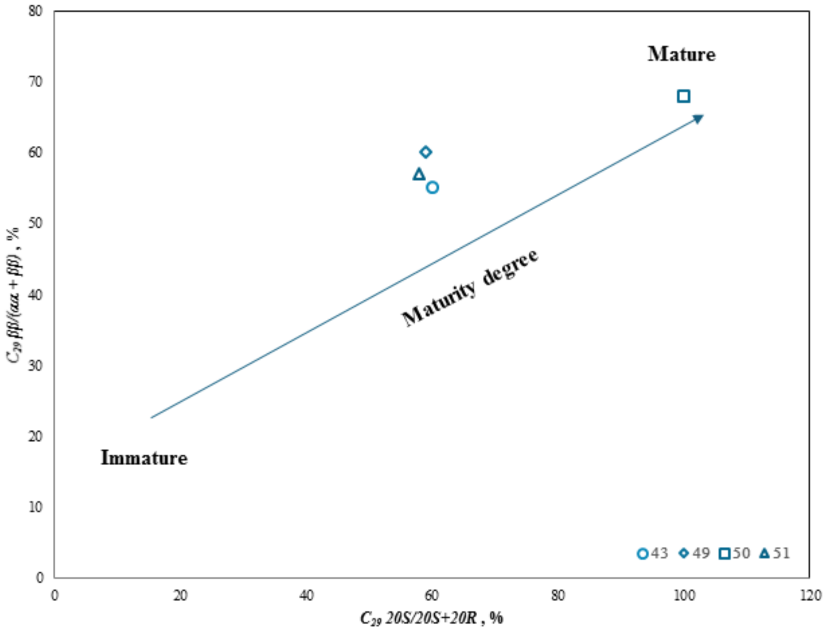

Figure 10 – C29 sterane maturation values C29 20S/20S+20R
and C29 ββ/(αα + ββ) [modified from 40]

Oil-to-Oil Correlation

A star diagram of normal alkane ratios showed that all oil samples have a similar distribution of light and heavy n-alkanes (Figure 11a). Furthermore, a star diagram of selected biomarker ratios for the studied oil samples demonstrates a similar pattern (Figure 11b). This suggests that these oils, despite being collected from different reservoirs, may have originated from the same source rock. All seven oil samples possess very similar characteristics, such as thermal maturity ranging from early to peak oil generation stages, marine reducing depositional conditions, and a carbonate source rock composition.

Conclusion

A comprehensive geochemical study of seven oil samples from Jurassic-Triassic deposits of the Emba region provided new data on the genesis and formation conditions of hydrocarbons in the region. Analysis of biomarker ratios (Pr/Ph, Ts/Tm, C_{29} steranes) and maturity parameters (CPI, C_{29} 20S/(20S+20R)) confirmed a marine carbonate origin for the oils, formed under reducing conditions. The obtained values of Ts/(Ts+Tm) (0.15–0.64) and C_{29} ββ/(ββ+αα) (0.55–0.68) indicate that the studied oils are within the early-mature and main oil windows.

The results revealed a high degree of genetic homogeneity among the studied oils, despite their collection from different stratigraphic horizons. This is supported by:

1. Similar distribution of n-alkanes and isoprenoids (Pr/Ph 0.79–1.07);
2. A unified organic matter type (predominance of C_{27} and C_{29} steranes);
3. Close values of maturity parameters.

Prospects for further research include expanding the sampling geography for more accurate oil correlation, applying isotopic methods to refine source rock age, and studying the influence of salt tectonics on hydrocarbon migration and accumulation processes. The practical significance of the work lies in the potential use of the obtained results to optimize exploration activities in the region and reduce geological risks during the development of new fields.

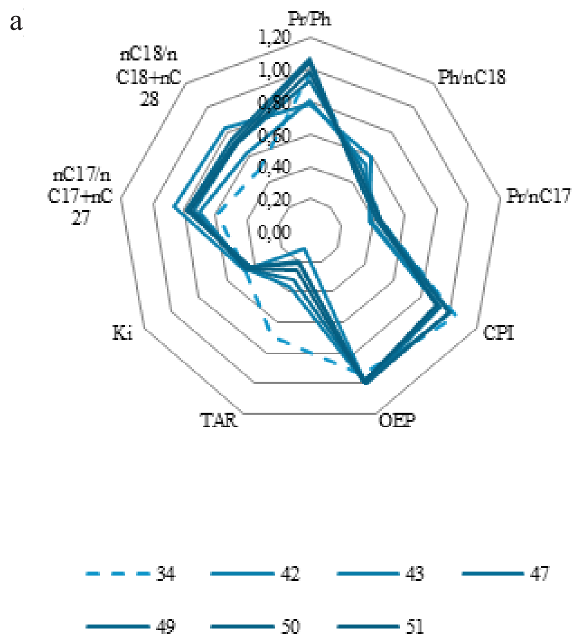

Figure 11a – Star diagram of normal alkane ratios

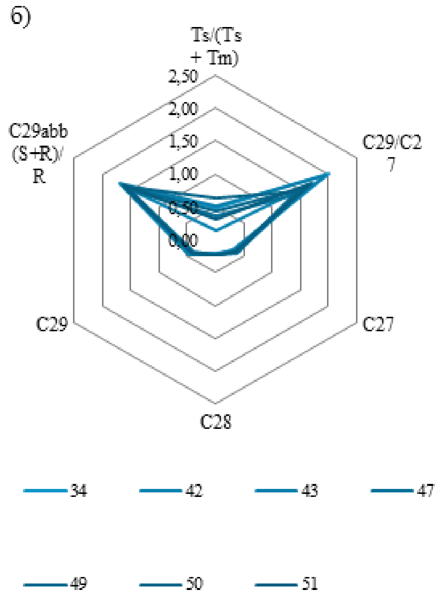

Figure 11b – Selected crude oil biomarker ratios for oil-to-oil correlation

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ЕМБІ АЙМАҒЫНЫҢ (КАСПИЙ АЛАБЫ) МҰНАЙЛАРЫНЫҢ МОЛЕКУЛАЛЫҚ ЕРЕКШЕЛІКТЕРІ: ШЫҒУ ТЕГІ, ТЕРМИЯЛЫҚ ЖЕТІЛУ ЖӘНЕ ГЕНЕТИКАЛЫҚ КОРРЕЛЯЦИЯ

Андатпа

Каспий алабы, оның ішінде оңтүстік-шығыс бөлігі, Теңіз және Қашаған сияқты қоры миллиард тонналармен бағаланатын алып кен орындары бар бірегей мұнай-газды аймақ саналады. Аймақта кең көлемде зерттеулер жүргізілгеніне қарамастан, мұнайлардың генетикалық жақындығы мен олардың палеоқалыптасу жағдайлары туралы мәселелер мұнай үлгілеріне қосымша геохимиялық талдау жүргізуді талап етеді. Ембі аймағы мұнайларын кешенді геохимиялық сипаттау және генетикалық корреляциялау, сондай-ақ мұнай түзілу жағдайларын реконструкциялау үшін молекулалық маркерлерді талдауға баса назар аударылып, әртүрлі стратиграфиялық горизонттардан жеті мұнай үлгісі алынды. Зерттеуде заманауи аналитикалық әдістер қолданылды: н-алкандар мен изопреноидтарды (пристан және фитан) егжей-тегжейлі талдау үшін газды хроматография (Agilent 7890B), ал терпандар мен стерандарды анықтау үшін таңдалған иондарды (m/z 191, 217) тіркеу режиміндегі хромато-масс-спектрометрия пайдаланылды. Негізгі геохимиялық индекстерді (изопреноидтық, гопандық, стерандық изомеризация коэффициенттері) есептеуге, сондай-ақ диагностикалық диаграммаларды құруға ерекше назар аударылды. Нәтижелер зерттелген мұнайлардың теңіздік шығу тегін және карбонатты ана жыныстардың басымдығын көрсетеді (C_{27} стерандар > 30%, C_{29}/C_{30} гопандар > 1). Pr/Ph қатынастары (0,79–1,07) және C_{35} гомогопандардың жоғары мөлшері мұнайдың тотықсыздандырушы жағдайда түзілгенін дәлелдейді. Термиялық жетілу параметрлері (Ts/(Ts+Tm) = 0,15–0,64; C_{29} $\beta\beta/(\alpha\alpha+\beta\beta)$ = 0,55–0,71) үлгілердің негізгі мұнай түзілу аймағында қалыптасқанын растайды. Генетикалық корреляция барлық үлгілерді теңіздік карбонатты текті бір мұнай тобына біріктірді. Алынған қорытындылар аймақтағы ұқсас кен орындарын болжау үшін практикалық маңызға ие.

Тірек сөздер: Каспий алабы, мұнай геохимиясы, ГХ-МС, биомаркерлер, термиялық жетілу, ана жыныстар, тотықсыздандырушы жағдай, теңіз ортасы, генетикалық корреляция.

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МОЛЕКУЛЯРНЫЕ ОСОБЕННОСТИ НЕФТЕЙ ЭМБИНСКОГО РАЙОНА (ПРИКАСПИЙСКИЙ БАССЕЙН): ПРОИСХОЖДЕНИЕ, ТЕРМИЧЕСКАЯ ЗРЕЛОСТЬ И ГЕНЕТИЧЕСКАЯ КОРРЕЛЯЦИЯ

Аннотация

Прикаспийский бассейн, включая его юго-восточную часть, является уникальной нефтегазоносной провинцией с гигантскими месторождениями, такими как Тенгиз и Кашаган, запасы которых оцениваются в миллиарды тонн. Несмотря на обширные исследования региона, вопросы генетической принадлежности нефтей и условий их палеообразования требуют дополнительных геохимических анализов нефтяных проб. Для проведения комплексной геохимической характеристики и генетической корреляции нефтей Эмбинского региона с акцентом на анализ молекулярных маркеров для реконструкции условий нефтеобразования было отобрано семь нефтяных проб из различных стратиграфических горизонтов. В исследовании использовались современные аналитические методы: газовая хроматография (Agilent 7890B) для детального анализа н-алканов и изопреноидов (пристана и фитана) и хромато-масс-спектрометрия в режиме регистрации выбранных ионов m/z 191, 217 для идентификации терпанов и стеранов соответственно. Особое внимание было уделено расчету ключевых геохимических индексов (изопреноидных, гопановых, отношений стерановой изомеризации), а также построению диагностических диаграмм. Результаты указывают на морское происхождение исследуемых нефтей с доминированием карбонатных материнских пород (C_{27} стераны > 30%, C_{29}/C_{30} гопаны > 1). Отношения Pr/Ph (0,79–1,07) и повышенное содержание C_{35} гомогопанов свидетельствуют об образовании в восстановительных условиях. Параметры термической зрелости (Ts/(Ts+Tm) = 0,15–0,64; C_{29} ββ/(αα+ββ) = 0,55–0,71) подтверждают генерацию проб в главной зоне нефтеобразования. Генетическая корреляция объединила все образцы в одну нефтяную семью морского карбонатного происхождения. Полученные выводы имеют практическую значимость для прогнозирования аналогичных скоплений в регионе.

Ключевые слова: Прикаспийский бассейн, геохимия нефти, ГХ-МС, биомаркеры, термическая зрелость, материнские породы, восстановительные условия, морская среда, генетическая корреляция.