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Factors Controlling the Unusual Oil Composition Distribution in the Bangestan Reservoir, Dezful Embayment, SW Iran

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Abstract—Petroleum geochemical characteristics are a major parameter of hydrocarbon field development. The present study is an attempt to decipher the unusual Bangestan (Cretaceous age) oil distribution throughout the Ahvaz oil field, SW Iran, based on the SARA test and GC–MS analysis of selected oil samples. The results indicated that all analyzed oils belong to the paraffinic group. Hydrocarbon indicators, such as tricyclic triterpane C_{22}/C_{21} (high), C_{24}/C_{23} and C_{26}/C_{25} (low), and hopane $C_{31}R/C_{30}$ (high) ratios and C_{25}/C_{26} ratio vs. C_{25}/C_{26} tet ratio, show that these oils are sourced from carbonate–marl rocks. The high saturation/aromatic hydrocarbon ratio in these oil samples may be related to long migration or high maturity. The biomarker variation exhibits a marine environment for the source rocks deposition. The observed oil maturity trend is showing a good correlation with the prevailing geothermal gradient and possible basement faults and fractured system. The increasing oil maturity in the eastern part of the field may be related to a heat flow anomaly. It seems that the area around well C (the area of wells C, D, or E) can be considered a petrochemical separator of fluids for two sides of the field. Therefore, it can be concluded that the observed petrochemical pattern is a complicated response of several factors: the presence of a palaeohigh, basement-controlled faults, petroleum source rocks, fractured system, and geothermal gradient variation in this deep reservoir.

Keywords: oil maturity, palaeohigh, basement faults, Bangestan reservoir, Ahvaz oil field

INTRODUCTION

The world's most important oil/gas reservoirs and two-thirds of the Middle East reservoirs belong to the carbonate type (Edgell, 1997). Therefore, it is necessary to pay individual practical attention to geochemical studies of these reservoirs, which will help to develop oil fields in this region.

Geochemical analysis is used for oil-oil matching and oil-source rock matching (Tissot and Welte, 1984; Peters and Moldowan, 1993; Peters and Fowler, 2002; Moldowan et al., 2012; Dongmei et al., 2013), oil migration (Terken and Frewin, 2000; Alimi, 2005), reservoir management (Kaufman et al., 1990; Miller, 1995), and basin modeling (Peters and Isaksen, 2000) in a carbonate reservoir. The oil of the Bangestan reservoirs is generated by source rocks of the Kazhdumi and Garo formations (Bordenave and Burwood, 1990).

It seems in some oil fields that the Pabdeh and Kazhdumi formations are in the oil window before 1–10 Ma (Bordenave, 2002), though it does not apply to all of the Zagros area. Since the discovery of oil in Iran, during the last century many studies of the Bangestan and Asmari reservoirs have been conducted; they are concerned with the geochemistry of source rocks, oil reservoirs, oil classification, relationship between the oil reservoir and source rocks, and correspondence between maturation, migration, and accumulation of hydrocarbons in oil reservoirs.

However, in spite of many studies of petroleum geochemical characteristics in Zagros, many doubts remain about the generation, migration, and accumulation of oils in the selected reservoirs. These studies cover only a part of the events related to oil prospects. Here some of these activities are mentioned.

The first serious geochemical study in Iran dates back to 1967. Bordenave was assisting with a project started by the former Oil Consortium when geochemical studies began, and they continued until 1978. Studies were performed to evaluate the characteristics and distribution of source rocks as well as correspondence between oil-source rock and the tectonic regions of Fars, Khuzestan, and Lorestan (unpublished report, 1973).

The age of oil source rock was estimated using the oil compounds at the Early Cretaceous for oil of Asmari and at 65 to over 120 Ma for oil of the Sarvak reservoir (Young et al., 1977). Bordenave and Burwood (1990) have most complete studies about the distribution of source rocks and oil maturity using the geochemical parameters of carbon and sulfur isotopes and biomarkers in the Zagros basin. Due to

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the end of the era of easy oil extraction, thorough studies of geochemical properties and assessment of factors of the oil reservoirs affecting these properties are very important. The geochemical characteristics of oil play a decisive role in the exploration, extraction, field development, and drilling of new wells.

To clarify different oil compositions, characteristics of the Bangestan reservoir, and asphaltene production in the Ahvaz oil field, the Iranian South Oil Industry decided to study their relationships. Therefore, the goals of the study were to investigate changes in the geochemical properties of oils and to determine the oil maturity in different wells and responsible geological reasons in the oil field.

LOCATION OF THE AHVAZ OIL FIELD

The Ahvaz oil field, which is adjacent to the city of Ahvaz (Fig. 1), includes three reservoirs: Asmari (Oligo-Miocene), Bangestan (Cenomanian–Santonian), and Khami (Neocomian–late Aptian). The Bangestan reservoir has better reservoir properties than most of the reservoirs in the central region of Khuzestan. The field is located at 48° 30′–49° N and 30° 30′–31° E, at the southern boundary of the Dezful Embayment, which is a part of the Zagros fold belt (Pliocene) in the northeastern Arabian Plate (Jackson and McKenzie, 1984; DeMets et al., 1990). The thickening of this area is caused by collision between Central Iran and Arabian Plates (Berberian and King, 1981; Berberian et al., 1982; Berberian, 1983; Agard et al., 2011; Allen et al., 2013). The field extends for 65 km and for 4–6 km at the top of the Bangestan reservoir.

Numerous works were published on several aspects of the Dezful Embayment, such as separation and folding of the Phanerozoic sedimentary rocks (James and Wynd, 1965; Huber, 1977; Berberian and King, 1981), Zagros Precambrian basement (Berberian, 1976, 1977, 1981; Berberian and Tchalenko, 1976a,b; Berberian and Papastamatiou, 1978),

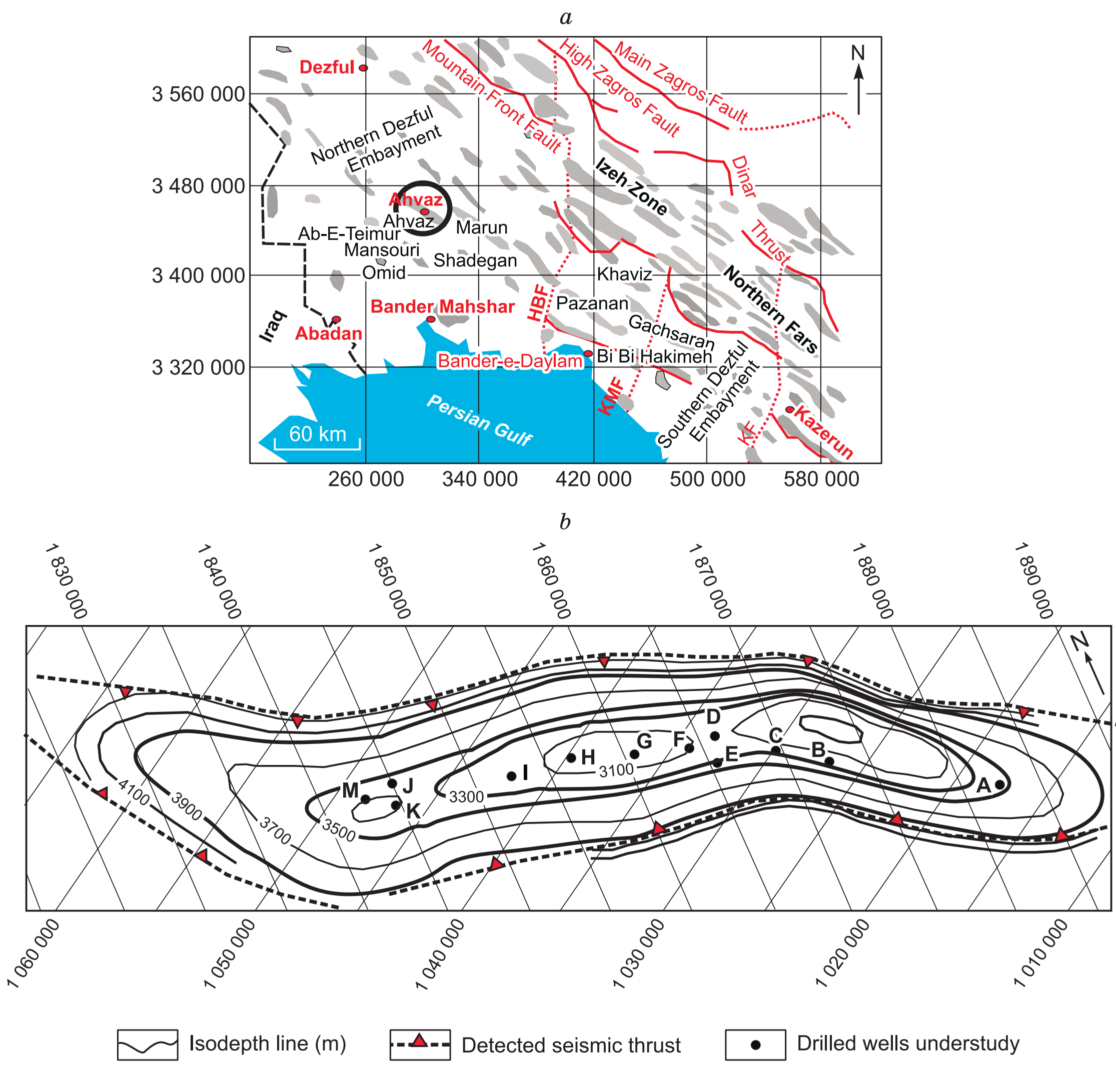

Fig. 1. Geographic location (Sherkati and Letouzey, 2004) (*a*) and UGC map based on the Ilam Formation top with the position of the studied drilled boreholes (*b*) of the Ahvaz oil field.

uplift rate in the late Pliocene (about 1 mm/yr) (Lees and Falcon, 1952; Lees, 1955; Falcon, 1974; Vita-Finzi, 1979) and this rate in the Holocene (6.6–8.1 mm/yr) (Vita-Finzi, 1987), shallow sediment folded belt (McKenzie, 1972; Jackson, 1980; Jackson and Fitch, 1981; Kadinsky-Cade and Barazangi, 1982; Jackson and McKenzie, 1984; Ni and Barazangi, 1986), and petroleum prospects (Bordenave, 2002; Bordenave and Hegre, 2005; Ghanadian et al., 2017; and others).

METHODS

This study describes changes of the geochemical properties of oil from the Bangestan reservoir of the Ahvaz oil field. In this case 12 samples of crude oil were analyzed in the Geochemical Laboratory of the Oil Industry Institute (Tehran) (Table 1). Primary tests were done by asphaltene precipitation and column chromatography to separate and identify the components of oil. The mean geothermal gradients in drilled wells (more than 500) were calculated, and its whole distribution was modeled. The fracturing system of the field was also modeled according to image log data.

The results of the present work can be divided in two parts: (1) oil fractions and (2) biomarkers.

Oil fractions

Oil fractions were studied using the SARA test (saturates, aromatics, resin, and asphaltene). In this method the crude oil compounds are split by polarization. The saturated part consists of nonpolar molecules which are cyclic, branched, or linear (paraffins), and aromatics include one or more aromatic rings that are hardly polarized. Resin and asphaltene consist of polarized molecules. Resin dissolves in heptane (or pentane), but asphalt cannot, and it is the way to differentiate between them (Fan et al., 2002). There are three ways: clay-gel adsorption chromatography (ASTM), high-pressure liquid chromatography (HPLC), and three-layer chromatography (TLC) or thin-layer chromatography with flame ionization detection (TLC–FID), which is faster and does not require extracting the asphaltene before analysis. The results of analysis of the oil fractions present in the Ahvaz oil field (Table 1) show a high percentage of saturated fractions (paraffinic oils). The high saturated to aromatic hydrocarbons ratio illustrates that a part of oil in the reservoirs is highly mature.

Biomarkers

Biomarkers are all organic compounds which exist in rocks, sediments, and crude oil and have a structural skeleton typical of living organisms; generally, the biomarker diameter is less than 30 nm. The spatial arrangement of these compounds is highly variable, and that is why they can be linked directly to a specific group of plants, animals, or bacteria. To be considered a good biomarker, compounds need a special structure, with high concentrations of living organisms. In addition, the biomarker compound must have sufficient resistance to degradation during diagenetic and catagenetic processes. Several studies of biomarkers were conducted in the Zagros region, southwestern Iran (Alizadeh et al., 2007; Soleimani and Zamani, 2015). The biomarkers can be used in determining the age of source rock, oil maturity, and sedimentary environment.

DISCUSSION

The data were classified into sets to interpret the results and find their relationship with geological parameters.

Oil fractions data analysis

According to geochemical analyses data (Table 1), the ratio increases eastward, relatively (1:3 in the west and 1:9

Table 1. Column chromatography data on Bangestan oils, Ahvaz oil field

Well no.		Parameters									
		Sat, %	Aro, %	Res, %	Asp, %	Res/Asp	Sat/Aro	Asp/Res	Sat/Asp	Sat/Res	Aro/Res
NW	M	44.40	33.70	18.70	3.30	5.666	1.32	0.176	13.454	2.374	1.8
	J	51.80	33.80	13.10	1.30	10.076	1.53	0.099	39.846	3.954	2.58
↓	K	33.60	38.30	18.50	9.70	1.907	0.88	0.524	3.463	1.816	2.07
	I	36.80	35.10	14.60	13.50	1.081	1.05	0.924	2.725	2.520	2.4
	H	34.90	34.50	15.30	15.20	1.006	1.01	0.993	2.296	2.281	2.25
	G	32.60	35.60	16.90	14.90	1.134	0.91	0.881	2.187	1.928	2.1
	F	30.10	35.30	16.40	18.20	0.901	0.85	1.109	1.653	1.835	2.15
	E	57.9	28.8	9.4	3.9	2.410	2.01	0.414	14.846	6.159	3.06
	D	32.60	35.60	17.00	14.80	1.148	0.92	0.870	2.202	1.917	2.1
	C	46	30.7	11	12.3	0.894	1.50	1.118	3.739	4.181	2.79
	B	48.4	29.9	9.6	12.1	0.793	1.618	1.260	4	5.041	3.11
SE	A	54.6	28.6	9.1	7.7	1.181	1.909	0.846	7.090	6	3.14

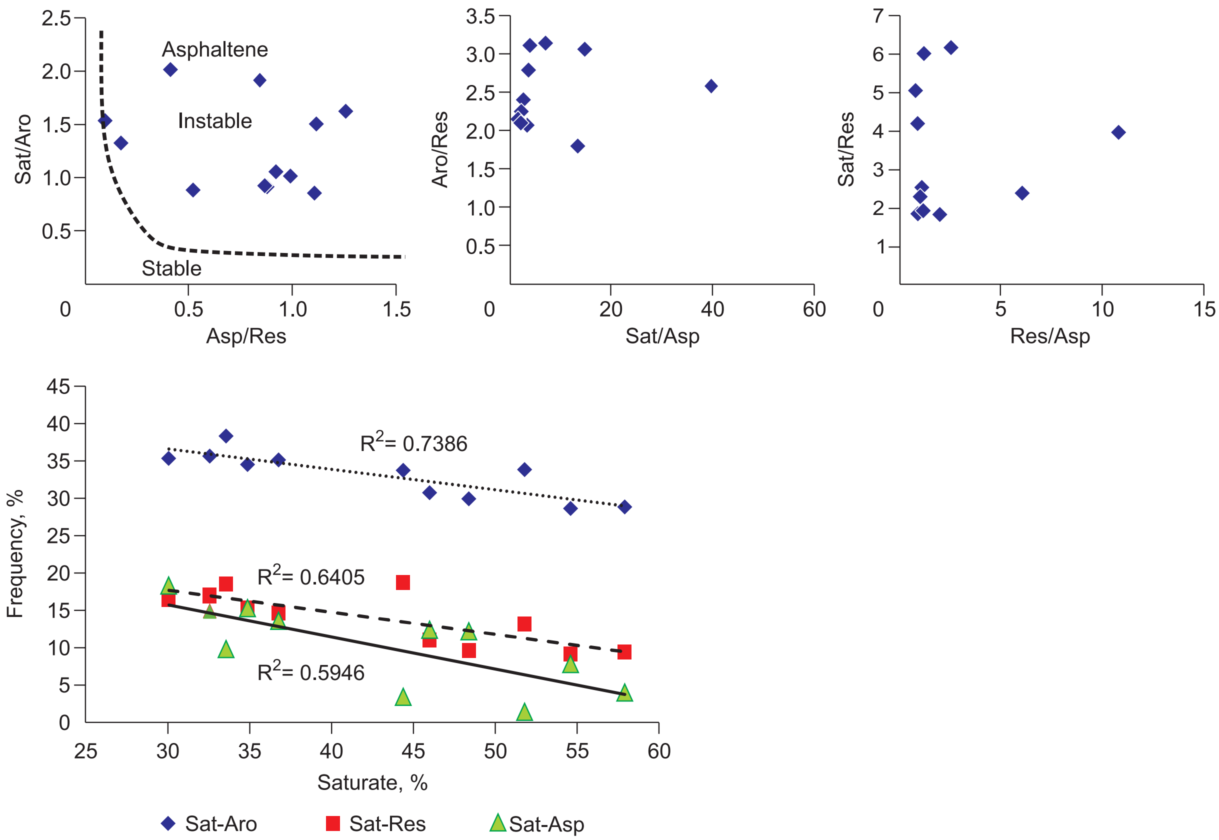

Fig. 2. Variation of the Asp/Res–Sat/Aro and Aro/Res–Sat/Asp ratios and Sat–all fractions in oils under study. The curve in the Sat/Aro–Asp/Res plot is modified after (Stankiewicz, 2012).

in the east). The amount of resin decreases toward the east. The amount of asphaltene increases from west zone to central field and decreases from center to east field. The immature, heavy (with a low API gravity), or biodegraded oils have a high amount of asphaltene (Stankiewicz, 2012). The colloidal instability index (CII) is the ratio of Sat/Asp to Aro/Res showing that the asphaltene is more unstable when the index is higher. Also, the ratio of Asp/Res is the unstable index. If this index is more than 0.35, there is the possibility of instability (Asomaning and Watkinson, 1999). Therefore, increasing the Asp/Res ratio illustrates more instability (Al-Atar and Watkinson, 2001). The ratio of Sat/Aro also predicts instability, as small amounts of asphaltene show instability in a paraffin solution. According to the changes of the index mentioned, the Bangestan reservoir behaves differently from the rest of the oil field and illustrates asphaltene instability (Fig. 2). Therefore, it deals with asphaltene precipitation.

Age of source rock

The sterane ratio C_{28}/C_{29} of organic materials extracted from organic-rich rocks decreases with increasing geological age. This ratio can be determined for oils and can be used for estimating the source rock age. These changes can be attributed to the evolution of the organisms. This ratio in the oil sample from the Bangestan reservoir of the Ahvaz oil field is 0.9 to 1, which represents the beginning of the Cretaceous. According to the candidate source rocks in the Zagros stratigraphic column, that could be associated with the Gadvan and Kazhdumi Formations. Oleanane content increases with thermal maturity (Rangel and Hernández, 2007) and is found more in drilled wells A, B, C, and E (ranges from 0.79 to 0.092). Oleanane and Gam/C_{30}H in the analyzed samples are less than 0.3 and 0.18, respectively. Therefore, the effects of oil contamination with younger extracted petroleum source rocks, such as those of the Gurpi Formation (Late Cretaceous: Campanian–Maastrichtian), might be invalid, but the presence of oleanane may be influenced by thermal maturity (Moldowan et al., 1994). The Gam/Hop ratio is relatively low in the studied oil samples, indicating the input of marine organic matter (Roushdy et al., 2010). The ratio can also denote the salinity variation of the depositional environment (Grantham et al., 1983; El-Sabagh et al., 2018), indicating a decreasing trend from east to west of the field. This ratio was also used to interpret oil maturity (Roushdy et al., 2010) due to its sensitivity to oil source rock.

Waples and Machihara (1991) suggested that a relatively high portion of C_{29} steranes signify crudes derived from deltaic or proximal marine sequences. All these characteristics are relevant to the Kazhdumi and Gadvan Formations.

Maturity determination

The oil maturity can be measured by the extent of isomerization in the cycloalkane biomarkers category in hopane and sterane. The range of hydrocarbon biomarkers used for maturity determination is the ratio of hopane isomerization C_{32}, S/S + R_{22}, Ts/Ts + Tm, C_{30} moretane/C_{30} hopane, C_{29} sterane/20 (S/S + R), and C_{29} sterane ββ/ββ + αα. The hopane isomerization C_{32} S/S + R in the sample is 0.56–0.59, which means 0.52–0.61 in the equivalency value, illustrating a maturity of more than 0.6 VR_o (Schoell et al., 1983; Zumberge, 1987; Raina et al., 2013). In the samples the ratio $C_{30}M/C_{30}H$ changes from 0.06 to 0.15, which represents fair maturity (Mackenzie et al., 1980; Seifert and Moldowan, 1980; Onojake et al., 2015). Ts/(Ts + Tm) represents oil maturity (Roushdy et al., 2010; Akande, 2012). In Figure 3, in spite of decreasing trends from both sides toward the center of the field, well E, which is located opposite well site K, has attained higher maturity (like well C) than the other wells. Sample M shows a lower value of C_{29} sterane/20(S/S + R), which seems to be sourced from horizons with a larger input of land plants. However, all the wells are close to one another but illustrate the different maturity degrees, which can be interpreted as a direct relationship between the thermal gradient (Fig. 7) and oil maturity. The main factor for increasing geothermal gradient is the tectonic activity of the basement faults in this area (Fig. 7).

The results inferred from Fig. 3*d* are correlated well with the position of well sites and possible faults in the field. However, the observed differences revealed that thermal gradients are not the same over possible faults (unpublished NISOC report,) throughout the field. It seems that well C has reached higher thermal maturity in view of the methylphenanthrene indices (MPI-1/MPI-2) ratio. Density fractures may play an important role due to the heat transferring process.

The MPI (Radke et al., 1986; Radke, 1988; Peters et al., 2005; Omotoye et al., 2016) in these oil samples are generally above 0.6 to 0.8 (Fig. 3*d*; Table 2), which suggests that they are mature and generated from a mature source rock (0.6 < R_o < 1.2% (Mackenzie, 1984)). The oil/condensate

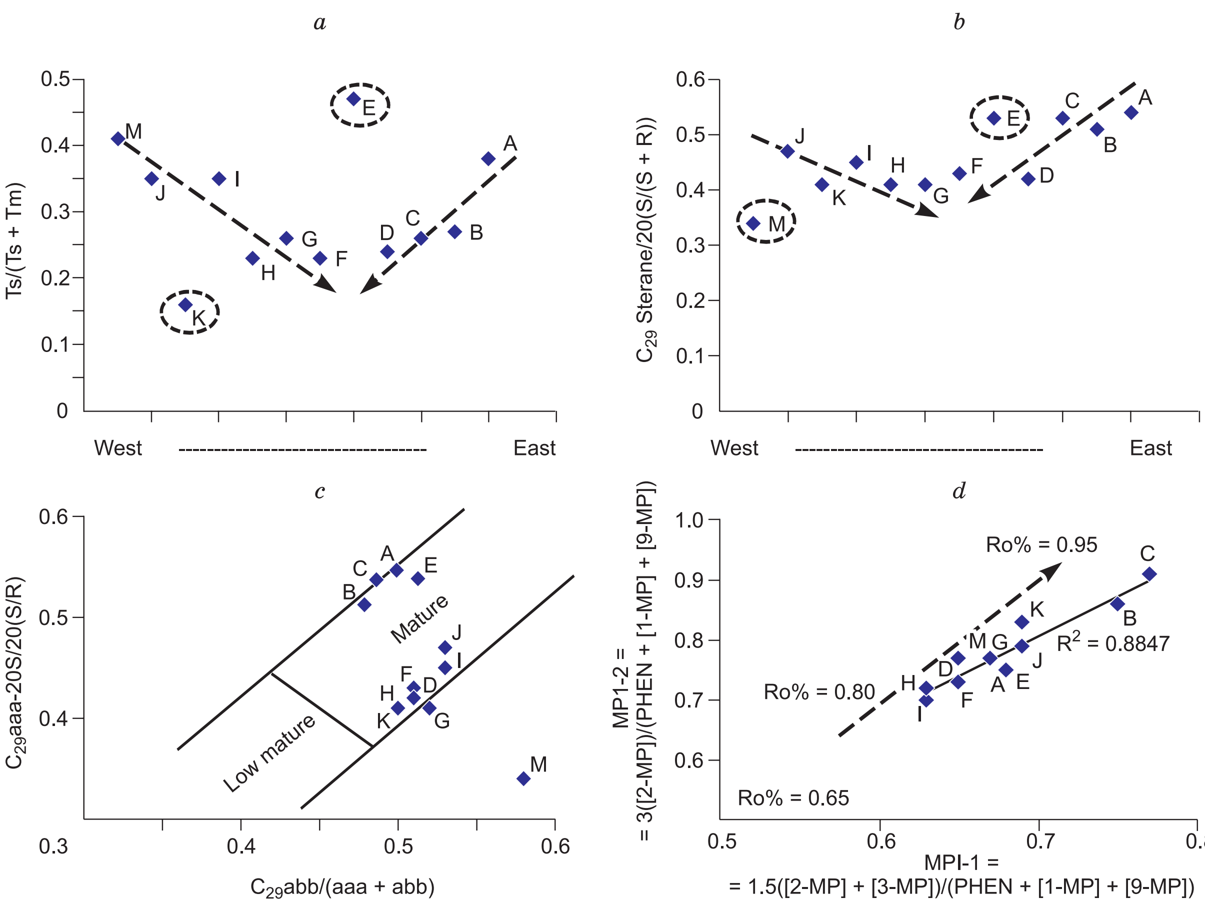

Fig. 3. The variation in biomarkers ratios indicating different maturities: *a*, Ts/(Ts + Tm); *b*, C_{29}S/20(S + R) ratios through the field; *c*, C_{29}aa-20S/(20R + 20S) vs. C_{29}abb/ (bbb + aaa) (original plot from (Duan et al., 2006)); *d*, MPI-1 vs. MPI-2 plots. Oil maturity in all the crude oil samples is not the same.

Table 2. Thermal maturity ratios of oils of the Bangestan reservoir: maturity-dependent ratios

Ratio	Drilled Wells											
	C	D	B	A	F	E	G	I	J	H	K	M
Ts/Ts + Tm	0.26	0.24	0.27	0.38	0.23	0.47	0.26	0.35	0.35	0.23	0.16	0.41
$C_{29}Ts/C_{29}N$	0.14	0.27	0.15	0.21	0.11	0.11	0.11	0.15	0.17	0.11	0.08	0.17
$C_{30}DiaH/C_{30}H$	0.08	0.08	0.07	0.08	0.01	0.01	0.01	0.02	0.03	0.01	0.0	0.03
Diast, %	27.2	34.5	25.7	31.7	16.3	16.7	16.9	18.2	19.4	16.5	16	23.7
Tricyclic ter, %	7.9	8.3	6.7	9.3	10.1	10.5	11	11.6	11.9	10.8	9.2	13
$Gam/C_{30}H$	0.18	0.12	0.18	0.14	0.06	0.06	0.06	0.04	0.05	0.06	0.07	0.05
MPI-1 = 1.5 (2-MP + 3-MP)/ (PHEN + 1-MP + 9 -MP)	0.77	0.68	0.68	0.75	0.65	0.67	0.65	0.63	0.69	0.63	0.69	0.67

threshold is also believed to be around VR_o = 1% (van Graas, 1990); therefore, no one of the selected oil samples is of the condensate type. Using this index is probably a more realistic approach (Mackenzie, 1984); however, Duan et al. (2006), based on their results, suggested that these indices do not reflect the maturity of oils. The present data indicated that the MPI-1/MPI-2 ratio is not correlated with Ts/Ts + Tm but rather is showing a regular trend (Fig. 3*d*).

The ratio Ts/Ts + Tm in oils exhibited a high maturity for sample E. As noted in the literature, this ratio is increasing rapidly at high maturity (van Graas, 1990). However, fracturing, heat transferring rate, source rock types, and oil composition changes in the reservoir are factors which are responsible for the observed discrepancies of data and, therefore, caution is necessary in oil interpretation.

The comparison between the C_{22}/C_{21}, C_{24}/C_{23}, and C_{26}/C_{25} ratios of the wells under study is shown in Fig. 4; they represent the source rock lithology (first two indices) and sedimentary environment, respectively (Liao et al., 2012). Marine organic materials are detected by the high portion of C_{23} (Aquino Neto et al., 1983; Philp and Gilbert, 1986). The crude oils that were studied in this field have high levels of tricyclic terpanes C_{22}/C_{21} (0.4–1.06) and a low C_{24}/C_{23} ratio (0.3–0.67), which points to carbonate marl source rock.

The main application of the C_{35}/C_{34} ratio (0.84–1.53) is determining the lithology of source rock. The high amounts of $C_{31}R/C_{30}$ hopane for crude oils of the Bangestan reservoir confirmed that the lithology of source rock is carbonate–marl. Triterpanes C_{29}/C_{30} can be found almost in all the oils; C_{29} in the carbonate source rocks and oils generated by them is higher than C_{30}. The values which are above 1 (except well E) indicate oils produced from carbonates and evaporates that are rich in organic matter (Connan et al., 1986; Waples and Machihara, 1991). Due to the range of this ratio in the samples under study that varies from 0.72 to 1.68 (Fig. 4), two trends were detected. It can be concluded that the petroleum source rocks of the Ahvaz oil field are bimodal: mostly shale in the east and mostly carbonate in the west, as it is shown in the previous figures. Also, the geological boundary of Bangestan oils separation (from center to east and west) seems to be around the location of wells C, D, or E (not a single line).

The GC-MS analysis of the saturated fractions and the triterpane Ts/Ts + Tm ratio (Fig. 5) show low to high levels of maturity ranging from 0.16 to 0.47 (Fig. 5*b*; Table 2). This ratio suggests that the oil samples are classified in three groups of maturity: (1) K; (2) C, E, B, F, G, and H; (3) A, D, I, J, and M. These variations are indicating that the oils may be sourced from parent rocks of different maturities.

Sedimentary environment

Oleanane is the specific biomarker that is a triterpenoid of nonbacterial origin (Onojake et al., 2015). It belongs to some angiosperms (flowering plants) and marks the Tertiary and Upper Cretaceous age source rocks and offshore environments.

Oleanane exists in most of oils and continental shales, almost in a delta environment (Ekweozor et al., 1981; Ekweozor and Udo, 1988; Cortes et al., 2013; El Diasty and Moldowan, 2013). If the oleanane index is higher than 0.3, it points to Tertiary rocks (Moldowan et al., 1994). According to Table 1 and Fig. 5, this index for the oils under study is very low (0.01–0.09), showing oils of marine origin (except samples E and A, which might have land sources). According to Fig. 6, the lithology of all the oil source rocks of the Bangestan reservoir is the same. The source is carbonate (or carbonate–marl). The ternary diagrams of distribution of the normal steranes and the respective C_{27}–C_{28}–C_{29} values (Huang and Meinschein, 1978; Mackenzie et al., 1982; Avramidis and Zelilidis, 2007) show a possible source from open marine to intermediate environment.

All these results show that the paleoenvironment is most probably intermediate–shallow open marine. Certainly, the effects of a paleohigh in this area cannot be ignored in basin geometry variation. This feature was mapped by Wood and Lacassagne (unpublished report, 1965) based on rudist distribution.

Unusual oil distribution in the reservoir

The relationship between oil maturity and geothermal gradient and fractures in the case study was also considered. The measured bottom holes temperature data indicated that

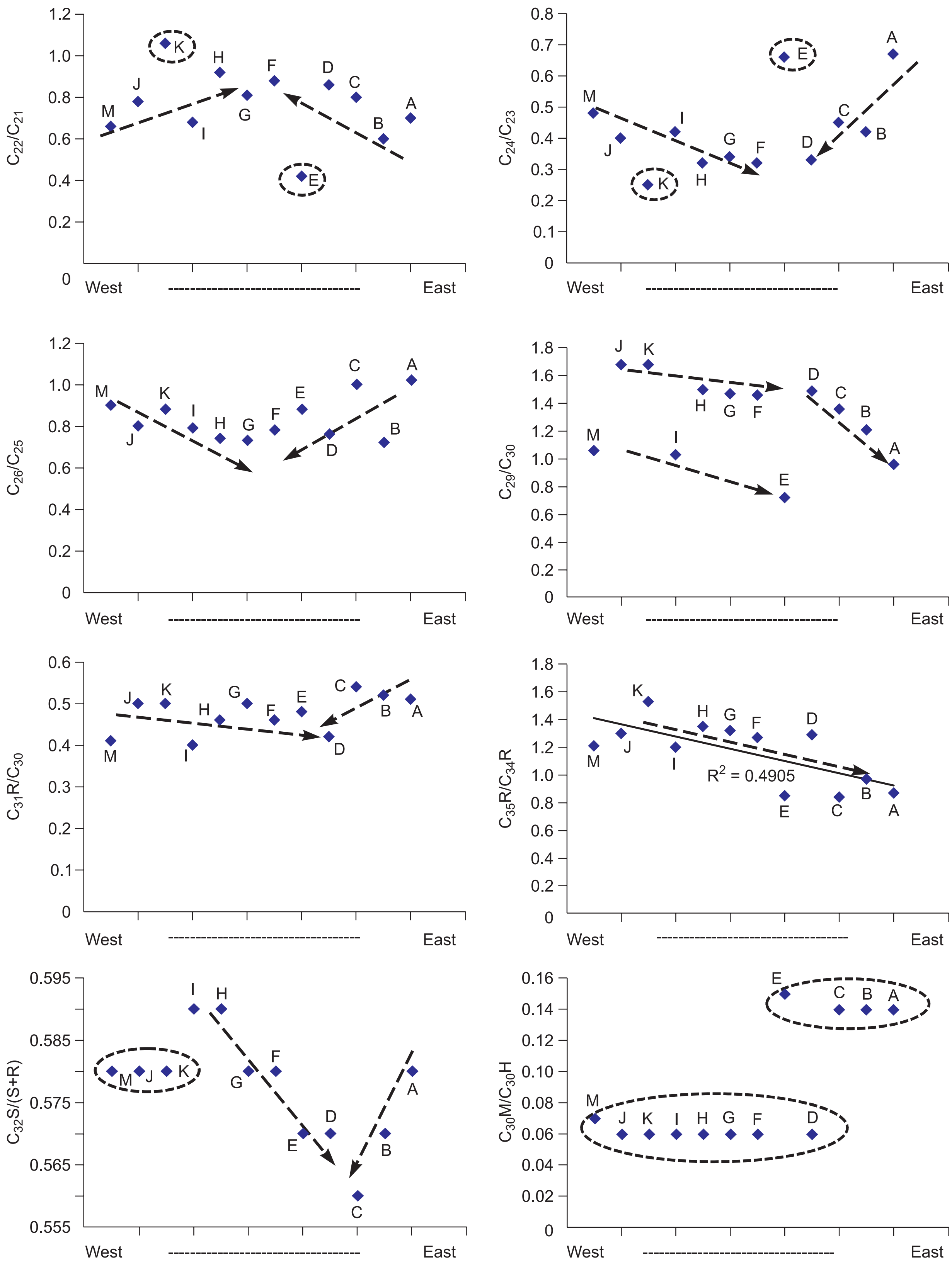

Fig. 4. Biomarker ratios plots presenting their variation through the oil field.

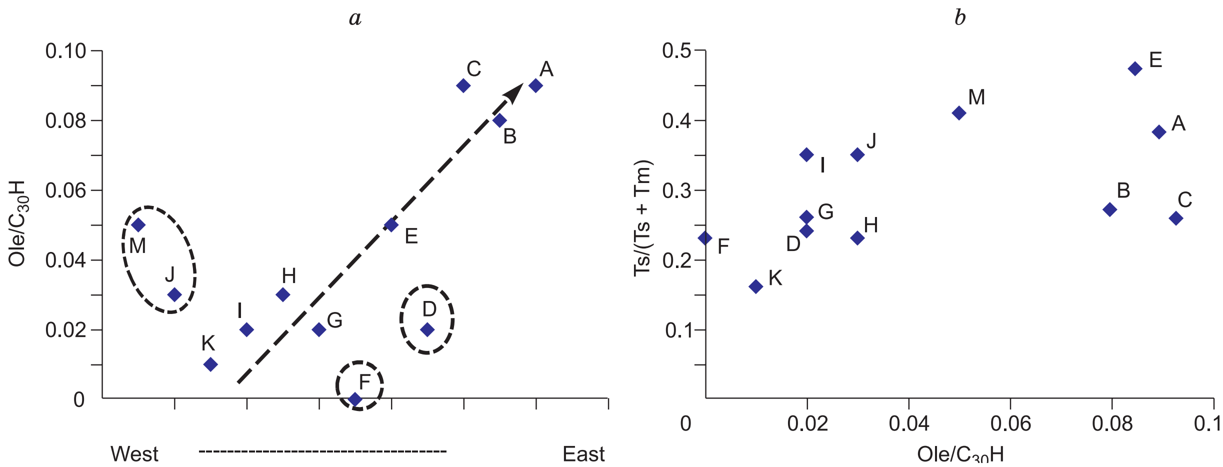

Fig. 5. Oleanane distribution in oils through the field (*a*) and thermal maturity (*b*) of the source rocks determined by a cross plot of the Ts/(Ts + Tm) ratios vs. Ol/C_{30}H.

the geothermal gradient of drilled wells in the Ahvaz oilfield changes significantly, as the average geothermal gradient changes from 20 to 26 °C/km. Also, in Fig. 7, the western boundary of the old heights (paleohigh) passes below the eastern culmination of the Ahvaz field. The geothermal gradient of wells B, C, D, E, G, H, and K significantly increased, but in well A it decreased. The fracture study of this oilfield showed four sets of fractures with strikes 5 N, 70 N,

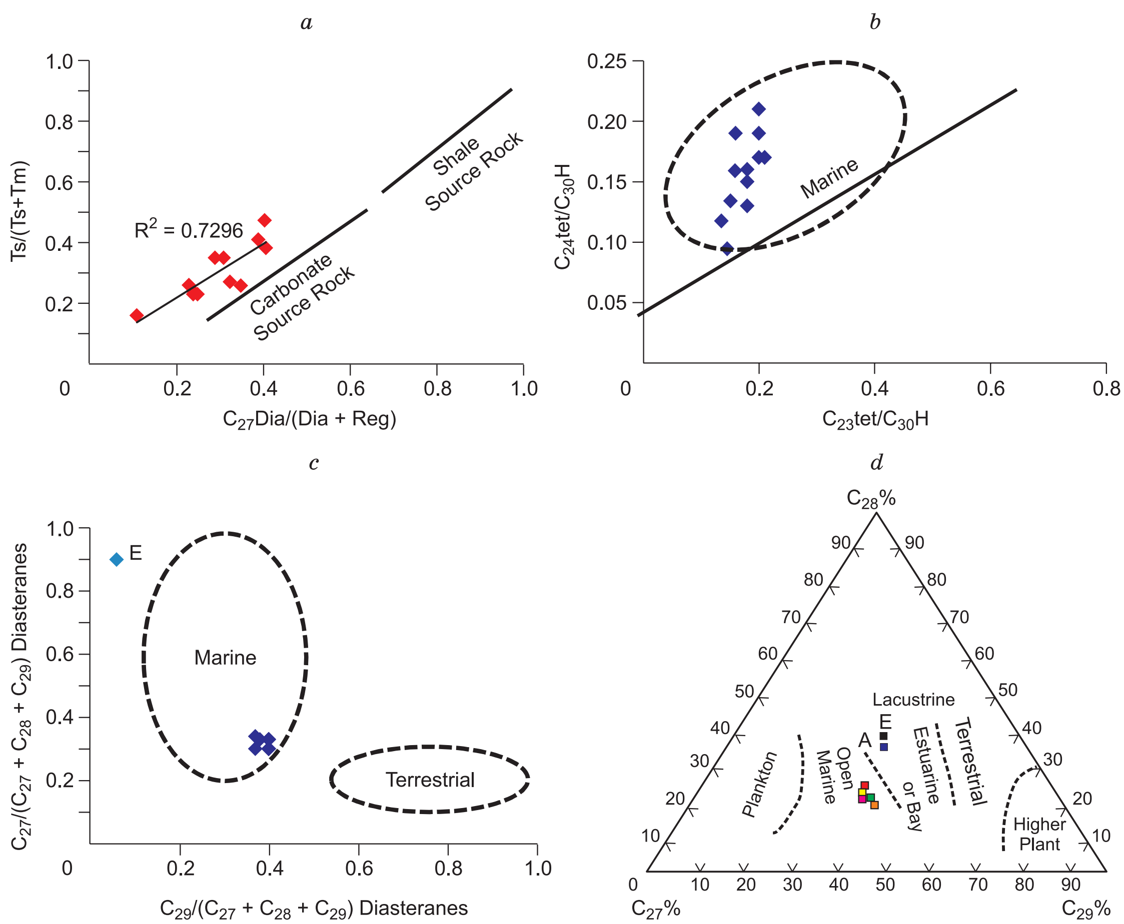

Fig. 6. Determination of the lithology and depositional environment of petroleum source rock using cross plots: *a*, Diasterane/(diasterane + sterane) and Ts/(Ts + Tm) ratios; *b*, C_{24}tet/C_{30}hop vs. C_{23}tt/C_{30}hop (line from (Tao et al., 2015)); *c*, C_{27}/diasteranes–C_{29}/diasteranes ratios; *d*, ternary diagram of C_{27}–C_{28}–C_{29}. All the diagrams represent an open marine to intermediate sedimentary environment for carbonate–marl petroleum parent rocks.

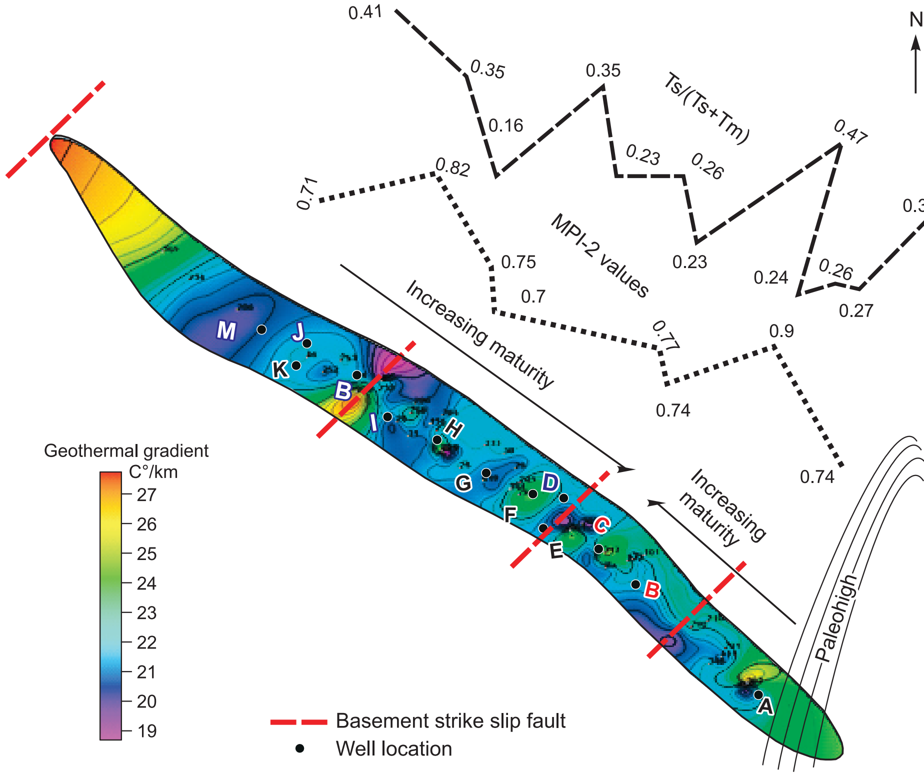

Fig. 7. Geothermal gradient map based on bottom borehole temperature data (unpublished NISCO report, 2008) and possible basement faults trends in the Ahvaz oil field (unpublished NISCO report, 2007). Well positions are relative. Maturity trend is based on the MPI (Fig. 3*d*).

30 N, and 120 N. The extension fracture set can be the most affected in oil production. The studied wells were shown on the fracture density map (consistent with production data) ((unpublished NISOC report, 2008) (Fig. 8)).

As shown in Fig. 8, the geothermal gradient is plotted based on the Bangestan bottom holes temperatures, which is indicating high variation individually in the eastern and western parts. The eastern part is characterized by the high

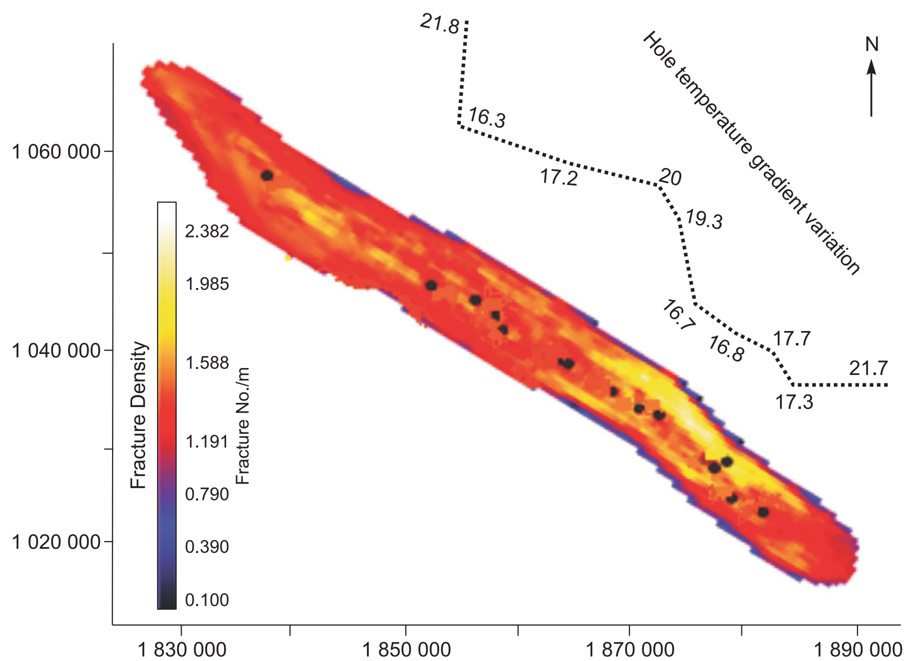

Fig. 8. Fracture density distribution and thermal gradient variation map through the Bangestan reservoir.

frequency of fractures. Increasing the temperature affects locally the differences in the biomarker ratios that represented maturity. In other words, increasing the temperature increases the oil maturity in that part of the field. As shown in Fig. 7, the scarcity of drilled holes with a high thermal gradient is observed in the eastern part, which is marked by high fracture density (unpublished NISCO Report, 2008) and, consequently, a high production rate.

According to the investigation of rudist distribution in this area (e.g., Esrafili-Dizaji et al., 2015), there might be buried paleohighs in the Zagros region. One of these is passing below the Ahvaz anticline, which crosses the end of the eastern edge of the field. The presence of a buried paleohigh and faults with the trends of south–north and east–west enhances the geothermal gradient (mean is 20–26 °C/km) and so produces an abnormal distribution, which is responsible for the different reservoir fluids maturity.

These factors also play an important role in generating the same characteristics in the adjacent fields. The remaining point is that these faults are also good conduits for hydrocarbon migration, since their sources are different in the field. Therefore, all the factors contribute to the unusual distribution, at least in the Bangestan reservoir. Fracture density is also indicating the same pattern, which verifies the effects of subsurface displacements. They also control the production rate in the field. However, these effects are obvious toward the eastern part of the field (around well C location, Fig. 1*b*).

CONCLUSIONS

The survey of oil fractions in a deep hydrocarbon reservoir associated with other geological information can improve the hydrocarbon distribution interpretation. The present data on the Bangestan oils having a high saturated to aromatic hydrocarbons ratio suggest a long migration path or relatively high maturity. The crude oils under study are sourced from organic-rich marl–carbonate rocks deposited in a marine environment in view of having triterpane tricyclic C_{22}/C_{21} (high), C_{24}/C_{23} and C_{26}/C_{25} (low), $C_{31}R/C_{30}$ hopane (high), and C_{25}/C_{26} ratio vs. C_{25}/C_{26} tet ratio.

The heat flow and its irregularity is the main factor in introducing different maturity of the Bangestan reservoir oils throughout the Ahvaz field. However, fracture sets also play an important role in easier heat transfer. Comparison of different ratios, such as C_{22}/C_{21}, C_{24}/C_{23}, C_{26}/C_{25}, $C_{31}R/C_{30}$, $C_{35}R/C_{34}R$, and C_{29}/C_{30}, indicated that the oil differentiation of the eastern and western parts of the field is located around well C. The presence of paleohighs, basement-controlled faults, petroleum source rocks, fracture density, and geothermal gradient variation influence the unusual oil composition distribution in this deep reservoir. It should be noted that oil interpretation should be done with caution in the same cases owing to the complexity of the factors controlling oil maturity.

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