**Geochemical investigation, Oil-Oil and Oil-Source Rock Correlation in the Dezful Embayment, Marun Oilfield, Zagros, Iran**

Elham Asadi Mehmandostia,[[1]](#footnote-1), Mohammad Hossein Adabib, Stephen A. Bowdenc, Bahram Alizadehd

a Department of Geology, Faculty of Earth Sciences, Kharazmi University, Tehran, Iran

b School of Earth Sciences, Shahid Beheshti University, Evin, Tehran, Iran

c Department of Geology and Petroleum Geology, University of Aberdeen, Aberdeen AB24 3UE, United Kingdom

d Faculty of Sciences, Shahid Chamran University, Ahwaz, Iran

**ABSTRACT**

Crude oils from Bangestan and Khami reservoirs, potential source rocks and reservoirs rocks from the Marun Field in the Dezful Embayment, Zagros Fold Belt Iran were subjected to geochemical analysis. Rock-Eval pyrolysis and biomarker thermal maturity parameters show that the Kazhdumi Formation (Fm.) is likely to be thermally mature (at least in the oil window) across the entirety of the Marun field, and that it has excellent generative potential as a source rock. The Pabdeh Formation has remarkable generative potential but is not thermally mature at the crest of the Marun field, but still it is likely to be thermally mature in synclinal regions to the NE and SW. The Gurpi Formation, although thermally mature (early oil window) in the studied samples has marginal generative potential. It is notable, therefore, that oils from the Bangestan and Khami reservoirs have biomarker characteristics that do not match bitumen obtained from the Kazhdumi Formation. Examples of this include the ratio of diasteranes to steranes, the proportions of different carbon numbered hopane homologues and the ubiquitous occurrence of alkylated-trimethyl-benzenes. These biomarker characteristics could only have been imparted to the Bangestan and Khami oils by a source rock other than the Kazhdumi Formation. Initially, this is debatable because the stable isotope composition of the Bangestan and Khami oils reported in previous work unambiguously correlate to the Kazhdumi Formation. Biomarkers are a quantitatively minor fraction of oil, thus it is possible that the biomarker characteristics of the oils was created by mixing Kazhdumi-bitumen with other petroleum from the Gurpi and Pabdeh formations. This could have if 1) multiple oil charges from different source kitchens filled the same reservoir, or 2) as oil migrated vertically from the flanks and crossed the Gurpi and Pabdeh formations – both of which have been considered regional seals. Either of scenario 1) or 2) points to a filling history more complicated than previously conceived.

***Keywords****:* Marun Oilfield; Bangestan Reservoir; Thermal Maturity; Oil-Source Correlation; Oil-Oil Correlation

**1. Introduction**

Almost all of Iran’s 136.2 billion barrels of proven oil reserves (Alavi, 2007), representing roughly 10 percent of the world's total oil reserves, are situated in the southwest part of Iran and in the Iranian part of the Persian Gulf. Most of these reserves were discovered in the Dezful Embayment, a depression located in the southern Khuzestan, which is part of the Zagros Fold Thrust Belt. The Dezful Embayment**,** which covers an area of only 60,000 km2, contains some 45 oilfields which account for more than 360 billion barrels of oil in-place, corresponding to approximately 8% of global oil reserves (Bordenave and Hegre, 2005). The productive structures are elongated anticlines, where the most prolific reservoir is by far the Oligo-Miocene Asmari Limestone. Subordinate reserves are located in limestone reservoirs of the Cretaceous Bangestan and Khami Groups in Lower Cretaceous ages (Figs 1-2).

The geological framework, stratigraphy and structure of the Zagros region has been extensively studied in detail (James and Wynd, 1965; Stöcklin, 1974; Ricou, 1974; Hessami et al., 2001; Sherkati and Letouzey, 2004; Sepehr and Cosgrove, 2004; Alavi, 2004 and 2007; Bordenave and Hegre, 2005 and 2010, among others). However, detailed work within this complex region remains necessary to improve our knowledge on the origin and interrelationship of individual hydrocarbon reserves.

The first comprehensive geochemical project in Iran was conducted by Bordenave and his coworkers (Bordenave et al., 1971; Bordenave and Sahabi, 1971; Bordenave and Nili, 1973; Burwood, 1978). This was in order to determine what formations acted as source rocks, their characteristics, thicknesses and distribution. Later they correlated oils with potential source rocks, using stable isotopes of source rock pyrolysates and oil, together with biomarkers. They came to the conclusion that most of the oil accumulating in the Asmari and Bangestan reservoirs of the main fields of the Dezful Embayment was generated from the Albian-aged Kazhdumi source rocks with minor charges from the Pabdeh Formation of Middle Eocene to Early Oligocene age (Bordenave and Burwood, 1990 and 1995). This petroleum system was found to be independent of older petroleum systems.

The Kazhdumi and Pabdeh source rocks reached the onset of oil expulsion during deposition of the Agha Jari Formation between 8 to 3 millions of years before the present, depending upon the location (Bordenave and Hegre, 2005 and 2010). This chronology has oil migrated from source rocks into preexisting Zagros structures; namely carbonate reservoirs in the Sarvak and Asmari Formations, Moreover, the Zagros folding induced prominent fracturing which can be observed both at outcrop and in wells. This fracturing, which affects limestones as well as marls, enhanced vertical migration of hydrocarbons towards the reservoirs. Generation, migration and entrapment of oil in the Zagros Fold Belt of Iran were influenced by orogenic events associated with the closure of South Tethys and particularly the deposition of the thick syn-orogenic Agha Jari Formation (Bordenave and Hegre, 2005 and 2010).

As far as the Marun area is concerned, oil samples from the Asmari and Bangestan reservoirs share similar stable isotope (δ13C and δ34S) compositions (Bordenave and Burwood, 1990). Oil samples from both the Asmari and Bangestan reservoirs of the Marun area were studied geochemically by Alizadeh et al., 2007. Cross plots of stable carbon isotope compositions of bulk fractions versus the Pr/Ph ratio indicate that both oils originated from the same shaley limestone of Mesozoic age (e.g. the Kazhdumi Fm.). Alizadeh et al. (2007) also showed that the H2S gas in the Asmari oil has a similar isotopic range as the H2S gas found within the Bangestan reservoir, suggesting a common source for the gas.

The purpose of the present study is to characterize source rocks samples in the Marun Anticline using the Rock-Eval method and to analyze bitumen samples extracted from the Pabdeh, Gurpi, Sarvak, Kazhdumi, and Dariyan formations and oils sampled from Bangestan and Khami reservoirs in the Marun Oilfield. We will determine: i) geochemical characteristics, ii) thermal maturity, iii) oil-oil and oil-source correlations, to gain an insight into the origin of the oil in this major oilfield.

**2. Geological setting**

The 65 km long and 7 km wide Marun oilfield is situated in the Dezful Embayment, which is part of the Zagros Fold Belt (Fig. 1a). The axis of the Marun anticline is slightly curved, being oriented NW to SE in its western part, and WNW to ESE in its central and eastern part (Fig. 1b). Overall 305 oil wells have been drilled in the Marun oilfield, of these only 4 wells have been completed in the Khami reservoir 17 wells have been completed in the Bangestan reservoir and the rest and by far the greatest majority have been completed in the Asmari reservoir (Shayesteh, 2002). The Asmari and the Bangestan reservoirs are assumed to connect and share the same oil-water contact (OWC) due to the extensive fracturing of the interval between the two reservoirs (McQuillan, 1973).

As shown in figure 2, the Permian to Early Miocene sedimentary section of the Dezful Embayment consists of a succession of basinal or platform high-energy limestones (the Khami, Bangestan and Asmari formations), and the low-energy argillaceous limestone and marls of the Garau, Kazhdumi and Pabdeh-Gurpi formations. Carbonate sedimentation was temporarily interrupted either by evaporitic episodes or by the sudden influx of siliciclastic sediments. Thick evaporitic sequences were developed as a result of arid climatic conditions during the Late Proterozoic (Hormuz Salt), Triassic (Dashtak Formation); Late Jurassic (the Gotnia and Hith formations), and towards the end of the Early Miocene (the Gachsaran Formation). As a result of the erosion of the Arabian Shield during sea-level lowstands and under humid climatic conditions, large quantities of siliciclastic sediments were transported into prodelta areas during the Middle to Late Barremian (Zubair Sandstones), Albian (Burgan Sandstones), and Early Miocene (Ahwaz/ Ghar Sandstones). Excellent source rocks were deposited during the Middle Jurassic (Sargelu Formation), Neocomian (lower part of the Garau Formation), Albian (Kazhdumi Formation), Early Cenomanian (Ahmadi Member/Shilaif Formation) and Middle Eocene/Early Oligocene (Pabdeh Formation), cf. Bordenave and Hegre (2005).

Thermal modeling based on studies by Bordenave and Hegre (2005) shows that for the current drainage area of the Marun Field, oil expulsion from the Kazhdumi Formation began 8 millions of years before the present in the deeper part of the Marun synclinal area (figure 1). The same study shows that at the top of the Marun anticline, after structural growth had already begun, expulsion commenced 5 millions of years before the present. Based on the structural setting, and the presence of extensive faulting and fracturing the same authors (Bordenave and Hegre (2005) expected near vertical migration of petroleum from the Kazhdumi source rock towards the Bangestan, then onto the Asmari reservoir. In addition, some oil may have been generated from the Ahmadi Member of the Bangestan group, and from the Pabdeh Formation, as these units are buried sufficiently deep in neighboring synclines within the Marun region. This creates a complicated charging scenario for structures in the Marun field but can be summarised as the potential for; 1) minor inputs of Pabdeh-petroleum supplementing charges of Kazhdumi-petroleum generated from source kitchens located in 2) synclines and more lartely 3) anitclines (Bordenave and Hegre, 2010).

**3. Analytical methods**

The National Iranian South Oil Company (NISOC) collected 87 cutting samples from different Marun wells for the present study. Among these samples, thirty cutting samples from 6 wells originated from different source and reservoir formations (Cretaceous-Tertiary in age) including Dariyan, Kazhdumi, Sarvak, Gurpi, Pabdeh and Garau formations were selected to determine the hydrocarbon generative potential.

Rock samples were powered after the removal of any superficial contamination and were subjected to analysis by Vinci Rock-Eval 6 Analyzer. The S1 and S2 signals (mgHC/g rock) were used to calculate the hydrogen index (HI = S2×100/TOC [mgHC/gTOC]) and the production index (PI = S1/(S1+S2). Tmax was used as a maturation indicator (Espitalié et al., 1977).

 Samples of source rock with >1 % TOC, and some samples of reservoir rocks (totally 19 rock samples) were solvent extracted with chloroform in a Soxhlet apparatus using cellulose thimbles (72 h).

Furthermore, 6 crude oils from the Bangestan and Khami reservoirs were selected for oil-source correlation.

The asphaltene fraction of the oil samples and rock extracts were precipitated by the addition of a 40 fold excess of *n*-hexane. The remaining maltene fractions were then separated into saturate hydrocarbons, aromatic hydrocarbons and resins by column chromatography, using alumina/silica gel (2/1 ratio) columns. These fractions were eluted with *n*-hexane, benzene and methanol, respectively.

Gas Chromatography (GC) of saturate hydrocarbon fractions was performed on a Vinci Technology 2010. GC instrument fitted with a silica column (25 m×0.22 mm) with a 0.25 µm coating and a Flame Ionization Detector (FID). Helium was used as the carrier gas. The GC oven was set at 50 ºC for 2 min and then programmed to 320 ºC at 5 ºC/min. The above analytical procedures were performed at the Petroleum Laboratory of Shahid Chamran University, Ahwaz, Iran. Saturate and aromatic fractions were analyzed by gas chromatography-mass spectrometry (GC-MS). Analyses were performed using a Hewlett Packard HP5970 mass selective detector attached to a HP5890 gas chromatograph. A DB-5 phase, 30 m length column with a 0.25 µm film thickness and 0.25 mm internal diameter was used for separation. The GC oven temperature program for the saturate fraction was 60 ºC for 2 min, heating at 4 ºC/min up to 290 ºC, and then holding for 30.5 min. For the aromatic fraction the program was 60 ºC for 0.5 min, heating at 5 ºC/min up to 290 ºC, and then holding for 32.5 min. For the quantitative determination of saturate and aromatic hydrocarbons, known amounts of the standard compound D4-cholestane were added to the oils and extracts prior to analysis by GC-MS. The above analytical procedures were performed at the University of Aberdeen, U.K.

**4. Results and Discussion**

*4.1 Rock-Eval Pyrolysis Data*

Rock-Eval pyrolysis results are given in Table 1. The S2 yields indicate the generative potential of source rocks. The S2 values of samples of both the Kazhdumi Fm. and the Pabdeh Fm. in the Marun region indicate a generally high generative potential for petroleum: the average values are 22 mg HC/g rock (maximum value attaining 31 mg HC/g rock) for the 5 Pabdeh samples, and 11 mg HC/g rock (maximum 18 mg HC/g rock) for the 16 Kazhdumi samples. The Gurpi Fm. samples from the Marun region have a much lower potential and are at most only a marginal source rock with a yield of 3 mg HC/g rock and S2 yields less than 4.0 mg HC/g rock, which are typically (Espitalié et al., 1985; Espitalié and Bordenave, 1993).

The low S1 yields (< 0.1 mg HC/g rock) of the Pabdeh samples indicate thermal immaturity – volatile hydrocarbons are not present, while the high S1 values of the Kazhdumi sample indicates that the Kazhdumi Fm. in the Marun region contains significant petroleum, and therefore had generated significant hydrocarbons. The high values of S1+S2 (up to 49 mg HC/g rock) confirm the outstanding hydrocarbon potential of the Kazhdumi samples as source rocks.

The average total organic carbon (TOC) values for the Kazhdumi samples we studied is 3.9 % (16 samples, maximum value of 6.2 %), while it is 4.3 % for the Pabdeh samples (5 samples maximum value of 5.9 %) and 3.4 % for one Garau sample. By contrast, the TOC of the Gurpi samples remained low (maximum 1.1 %, average 0.74 %, for 4 samples), indicating very marginal source rock potential.

A widely used method for classifying organic matter with Rock-Eval pyrolysis data employs a cross plot of hydrogen index (HI) and oxygen index (OI) parameters to recreate a representation of the van Krevelen diagram (Espitalié et al., 1977; Tissot and Welte, 1978). In this diagram, kerogens can be classified into Type I (very oil prone), Type II (Oil prone), Type III (mostly gas prone) and Type IV (inert) kerogens. The thermal maturation of each kerogen type is described by their pathways; the most thermally mature samples plot near the origin the graph. The position of the Marun samples on the Rock-Eval van Krevelen diagram (Fig. 3) indicates that Kazhdumi and Pabdeh kerogens are Type II, while the Gurpi Kerogen has very high oxygen index values and may be a mixture of mixed type II/III and even type IV kerogen. From their relative positions along their respective kerogen type-pathways, the Kazhdumi and Pabdeh samples are more thermally mature as compared to the Gurpi samples.

Despite the fact that the level of thermal maturation can be roughly estimated from the HI vs. OI plot described above, production index (PI) and in particular Tmax values are more typically used to estimate thermal maturity. In general, PI and Tmax values less than about 0.1 and 435 ºC, respectively, indicate thermally immature organic matter. Tmax values greater than 470 ºC indicate the wet gas zone. PI values reach about 0.4 at the bottom of the oil window and reduce to 0.1 or less when the hydrocarbon generative capacity of kerogens has been exhausted (Tissot and Welte 1978; Espitalié et al., 1985; Peters, 1986).

The Tmax range observed for the Pabdeh samples rang from 418°C to 429°C, with an average of 421°C which indicates thermal immaturity, the Gurpi samples are immature or marginally thermally mature as Tmax vary from 428°C to 435°C, with an average of 432°C, the Kazhdumi samples are into the oil window (438°C to 448°C, with an average 442°C). The plot PI vs. Tmax illustrates these results (Fig. 4), whilst plots of Tmax and PI versus depth (Fig. 5) confirm a general increase of Tmax and PI with depth, albeit with some scattering.

It should be underlined that these results are obtained from wells located on, or close to, the top of the Marun anticline, and that in the neighboring synclines, potential source rocks were buried much deeper (over 1 km), and would be expected to have reached a higher level of thermal maturity and also to have begun generation earlier (Fig.1c).

*4.2 Bulk geochemical composition and GC-Fingerprint*

The asphaltene contents of oils and reservoir extracts vary from zero to over sixty percent asphaltene (Table 2). Extracts from the Sarvak and Dariyan reservoirs sections have notably high asphaltene contents (tens of percent or greater) whilst oils produced from the Khami and Bangestan reservoirs are distinctly less asphaltic. However, while the Khami oil showed as zero percent asphaltene, the remaining Bangestan-oils still have a relatively high asphaltene content (up to 8 percent). While some of the differences between oils and reservoir rock extracts may be explained by different sampling methods (e.g. solvent extracts of reservoir rocks typically contain more asphaltenes than wellhead or DST-oils produced from the same unit –Tissot and Welte, 1978; Bayliss, 1998), the proportion of asphaltene is still significantly greater in the Savrak and Dariyan reservoirs. For these two formations this observation is consistent with reports by operations geologists of tar mats within these formations (personal communication).

From these high asphaltene values it might be expected that some biodegration of the oils has occurred (e.g. saturated and aromatic compounds removed and an enrichment in the less easily biodegraded asphaltene), but the GC-chromatograms and their envelopes do not provide evidence of this alteration process. Chromatograms of oils within reservoir formations at the present day, even for those with high asphaltene contents, show clear and prominent *n*-alkane and isoprenoids and little suggestion of a UCM relative to the clearly resolved peaks (figs. 6 and 7). Therefore there is no clear evidence, from GC-chromatograms for biodegradation of these oils (Peters et al., 2005).

The produced oils, with a few exceptions, are characterised by high proportions of phytane (Pr/Ph ratios are thus less than one). While there is variation in the pristane/phytane ratios of oils and reservoir extracts, the range covered is typical of that associated with oils derived from source rocks deposited within marine environments (Hughes et al., 1995).

The inferred depositional environments, for many of the potential source rocks in this region, would predict the presence of sedimentary organic matter derived from phytoplankton initially deposited in an anoxic sediments (Bordenave and Herge, 2010). Within these marine depositional settings, there would be proportionally lesser sources of pristane-precursor materials (e.g. tecopherols and similar compounds derived from woody materials – see Goossens et al., 1984) as well as decreased formation of pristane as a consequence of the oxidation of phytol during early diagenesis (ten Haven et al., 1987). Furthermore, if hypersaline conditions (e.g. within a sabkha environment) occur in the depositional environment the proportion of phytane can be increased because of the presence of halophilic archea, that yield sedimentary organic matter with high proportions of phytane (Love et al., 2005). Therefore, the general range and overlap of Pr/Ph values is reasonable for the essentially marine depositional environments suggested for source rocks in figure 2 (there is more phytane than pristane). Unfortunately, this also suggests that the Pr/Ph parameter will not help discriminate oils generated from different source rocks within the Marun Region. The few instances of very high Pr/Ph values may indicate oils generated during later stages of catagenesis – when greater proportions of pristane are liberated from kerogen (Goossens et al., 1988) – although this is not conclusive.

*4.3 Thermal Maturity*

A range of thermal maturity parameters were obtained from biomarker measurements performed on oils and rock extracts (Table 3). Interpretation of these parameters within a setting such as the Zagros belt is complicated because subsurface fluid migration can introduce foreign biomarkers into source rock formations that are unrepresentative of the formations thermal history (e.g. migrated petroleum from a different source kitchen).

A cursory screening of data can be obtained by cross plotting potential thermal maturity parameters by depth (Fig. 8) and comparing the results to the Rock Eval Tmax parameter (Fig. 9), the later being largely representative of the thermal maturity of kerogen which is immobile and consequently indigenous to the host formation. Indigenous petroleum should thermally mature with increased burial and depth, thus depth in the first instance can also be used to assess the robustness of a thermal maturity parameter. However, thrusting and periods of non-deposition will cause data to deviate from trend lines as is the case for any other thermal maturity parameter (Tissot and Welte 1978). Additionally it is important to remember that different parameters evolve at different rates – thus correlations between two parameters may not be linear and one parameter may also reach a plateau-value and (as discussed later) may even invert after attaining their maximum value (see Farrimond et al., 1998 for examples).

For source rock samples thermal maturity parameters based on comparisons between biomarker homologues with and without alkyl side chains generally show good correlations with both depth and Tmax (significant for alpha values of 0.0005 in the case of the pregnane/sterane parameter and significant at an alpha value of 0.01 for C20/C28 triaromatic steroid parameter). Changes in these parameters may represent the greater thermal stability of the steroid homologues without alkyl side chains or, more likely at higher thermal maturities, their formation by the cracking of larger compounds ([Sajgó](http://www.sciencedirect.com/science/article/pii/S0146638000000978), 2000). Matching these parameters directly to levels of thermal maturity in terms of oil generation is difficult from the data reported in Table 3 as the form in which they are reported is not common and hence not as well calibrated as other parameters. However, the large proportion of homologues without alkyl side chains found within the source rocks indicates a peak oil window level of thermal maturity, whilst the produced oils contain proportionally less of these compounds and would be interpreted as early oil window maturities (Mackenzie et al. 1981; [Sajgó](http://www.sciencedirect.com/science/article/pii/S0146638000000978), 1984). Thus, these parameters indicate that all source rock samples are more thermally mature than are the oil samples.

Extents of sterane isomerisation captured by the % C29 5α,11β,14β (H) parameter (C29 αββ/(αββ+ααα) sterane) and the % C29 5α,11α,14α (H) 20S (C29 ααα 20 S/ ααα 20 S + ααα 20 R) parameters are better calibrated with respect to oil generation. For both reservoir and source rock extracts (Figure 9) the % C29 5α,11β,14β (H) parameter place the samples at the boundary between the early oil window (values ~ 0.4) and the onset of peak oil generation, values close to 0.7 (Killops and Killops, 2005). The C29 5α,11α,14α (H) 20S parameter, which has been shown to invert at latter stages of the oil window (Bishop and Abbot, 1995; Farrimond et al., 1998), also indicates that the majority of samples are at an early to peak oil window level of thermal maturity. An examination of the source rock data indicated a correlation between these parameters and depth or the Tmax parameter is significant at alpha values of 0.02 or better, indicating they are reliable for picking up subtle changes in thermal maturity. The % C29 5α,11β,14β (H) parameter indicates that Bangestan oils are less thermally mature than neighbouring source rock samples (Figure 10).

Many hopane thermal maturity parameters reach their maximum or plateau values prior to, or just after the onset of oil generation (Farrimond et al., 1998; Peters et al., 2005). As oils are by definition typically generated at levels of thermal maturity equitable to the oil window the % C32 17α,21β(H) 22 S and similar parameters have little utility in this instance. However, there are other hopane based parameters that respond well to higher levels of thermal maturity, e.g. up to the onset of condensate formation (van Gras, 1990). The Ts/Ts+Tm parameter is one such example (Fig. 10), although starting value for this parameter depend on conditions during early diagenesis that influence the formation of various precursor hopanoid compounds (Telnas et al., 1992). After removal of two outlying data points this parameter correlates well with both depth and Tmax (an alpha value greater than 0.002). The range of values encountered for the Ts/Ts+Tm parameter would also suggest that source rocks in the Marun region are at the point of peak oil generation (Killops and Killops, 2005).

The methylphenanthrene ratio (MPR) and methylphenanthrene index (MPI) parameters can be converted to an equivalent value of vitrinite reflectance (Radke, 1988). The values predicted for the MPR parameter are similar, but slightly lower than those predicted by the Tmax parameter that can also be converted to vitrinite reflectance equivalence, VRE (~0.8 compared for the MPR parameter and 0.9 %VRE for Tmax). The overall level of thermal maturation suggested by both parameters is thus consistent with indications from other thermal maturity parameters e.g. the source rocks are at the point of peak oil generation. However, there is no significant correlation between phenanthrene derived parameters and depth or Tmax – suggesting that analytical imprecision or variations in organic matter type (Radke, 1988) exceed variation due to the marginally different levels of thermal maturation suggested by other indicators. Overall, particularly when expressed as VRE and the uncertainty that this involves, these parameters indicate a lesser difference in thermal maturity between source, reservoir rocks and oils than other thermal maturity parameters.

In summary, the source rocks from the anticline of the Marun region appear to be at the point of peak oil generation. But its notable that the biomarker fingerprint of oils produced from the Bangestan formation are less thermally mature (possibly even corresponding to an early oil-window charge) than those in the Sarvak and Dariyan reservoirs and the majority of source rock samples.

*4.4 Oil-oil and oil-source rock correlations*

The Pabdeh and Kazhdumi source rocks are both Mesozoic in age and were deposited in marine settings, in which bottom water anoxia facilitated the accumulation of organic matter (Bordenave and Hegre, 2010). Given this, it is not surprising that a number of oil correlation parameters don’t discriminate between source rocks or oils – e.g. the Pr/Ph as already described. Initially, the biota that inhabited these marine depositional settings wouldhave produced organic matter with similar geochemical and biomarker characteristics the reflect their marine character. However, despite the similarities in the biota that contributed sedimentary organic matter to the Pabdeh and Kazhdumi formations, the two formations are lithologically distinct. Biomarker parameters that reflect differing elements of lithological composition, early diagenetic history and sedimentary environment would be expected to better discriminate between the bitumen generated by the two formations.

Based on these criteria, the diasterane/sterane ratio would reasonably be expected to highlight key lithological differences between the Pabdeh and Kazhdumi formations. Diasteranes form by the clay-catalysed rearrangement of sterenes during early stage diagenesis (Moldowan et al., 1986; van Kaam-Peters et al., 1998): the consequences of this are that potential source rocks formed in clay-impoverished settings have a reduced capacity to form diasteranes. Carbonates accumulate in depositional settings where siliciclastic and clay sedimentation rates are low, thus carbonate-rich source rocks yield oils with lesser proportions of diasteranes (Peters et al., 2005). In this case, two out of the three samples of Pabdeh-marls have the lowest proportion of diasteranes, whilst the laminated Kazhdumi samples have the greatest proportion of diasteranes (Fig. 11). Relative to these bench marks Bangestan oils have values between the two source rocks. Other oils plot close to these except for the Sarvak. Because diasteranes are slightly more thermally stable than regular steranes, thermal maturity can influence this parameter. Given the relatively slight differences indicated for the thermal maturity of the source rocks, this effect is probably unimportant for the source rocks in this instance.

The ratio of C30 to C32 + C33 14α,17β (H) hopanes(Fig. 11) was used to fingerprint bitumens and oils (the C31, C34 and C35 hopanes could not be accurately measured in all samples). The carbon number distribution of hopanes found within source rocks is expected to be heavily dependent on conditions experienced by the sedimentary organic matter prior to its deposition and then subsequently during early diagenesis; oxic conditions, any areal exposure and long residence times for sedimentary organic matter generally lead to the loss of C31 – C35 hopanoids that are the precursors for C31 – C35 hopanes (Peters and Moldowan, 1991). Furthermore, sedimentary organic matter with plant components contains numerous sources of C30 hopanes (diploptene and diplopterol – Killops and Killops, 2005), and lesser amounts of hopanes with extended alkyl side chains derived from bacteriohopanol precursors (Rhomer et al. 1984). Thus, if the Kazhdumi (a more siliciclastic sediment) had received greater allocthonous inputs of land derived sediments including clay minerals and terrestrial organic matter it might be expected to generate bitumen with both more diasteranes and, contain greater proportions of C30 hopanes relative to higher carbon number hopane homologues. When diasterane/sterane data and C30/C32+ C33 hopane data are cross plotted most oil samples plot closest to the Pabdeh, but still between Pabdeh and Kazhdumi samples. The exceptions being the Garau and Sarvak extracts, and to a lesser extent the sample of Khami oil, that plot closer to the Khazdumi.. A similar grouping of samples on a cross plot can be obtained by using the C29/C30 hopane ratio which would be expected to reflect similar processes to the C30/C32+ C33 hopane parameter (e.g. enrichment of the lower carbon number homologues as biological precursors with higher carbon numbers are destroyed or altered during transport of the precursors sedimentary organic matter).

A distinctive feature of the Bangestan oils is the presence of clearly resolved alyklated trimethylbenzenes (ATMB) or aryl-isoprenoids (Fig. 12). A significant precursor for these compounds is isorenieratane – a derivate of a pigment found in green and purple sulphur bacteria that live in euxinic water columns (Summons and Powel, 1987). Although ATMBs can also be generated from numerous other sources during pyrolysis (Hartgers et al., 1992), and thus the presence of these compounds is best utilised rather than their palaeoenvironment significance. A cursory glance at figure 12 might be a little misleading regarding the abundance of ATMBs in samples as the Bangestan oils are less influenced by interfering compounds than the rock extracts; these latter samples could have been contaminated by numerous compounds during drilling operations (these compounds might correspond to the many unidentified peaks in figure 12 that appear to make the abundance of ATMBs seem very low). Despite this, a qualitative evaluation can at least be performed and the very low abundance of these compounds in the Kazhdumi relative to other samples is therefore notable. Higher carbon number ATMBs and iosrenieratane start to thermally degrade at levels of thermal maturity equitable to Tmax values above 430 deg. C (Requejo et al., 1992), but the low carbon number homologues persist much further into the oil window. Thus, these compounds had been present in the Kazhdumi at a prior and lower level of thermal maturity, should still be found at present day levels of thermal maturity. The absence of ATMB’s in Kazhdumi bitumen is thus significant and indicates an additional biomarker-characteristic of the Bangestan oils that this source rock can not account for the only source rock of the Marun Oilfield.

Thus biomarker evidence strongly points to Bangestan oils (and indeed the other oils to a lesser extent) being sourced from a mix of Kazhdumi and Pabdeh organic matter. But it is important to qualify this interpretation by nothing that the biomarker ratios used, do not permit a quantitative evaluation of the level of mixing. Thus, the Pabdeh may have contributed significantly to the Bangestsan oil-fingerprint without contributing significantly to its bulk oil composition.

**5. Conclusion**

This study has found that the crest of the Marun-anticline contains Kazhdumi source rocks that have been sufficiently heated to have generated petroleum. The Pabdeh and shallower units are of near oil window thermal maturity but are thermally immature, and although the Gurpi is on the threshold of oil generation its generative potential is low. The intervals of the Pabdeh Formation that are more deeply buried in regions to the NE and SW of the Marun region would therefore certainly have been heated sufficiently to have generated hydrocarbons. Synformal elements of the Dezful Embayment have long been considered to hold source kitchens, but our data would suggest that the Kazhdumi Formation is of oil window thermal maturity in the crestal portion of the Marun Field. Therefore, the Kazhdumi is a volumetrically very important source rock.

The Kazhdumi and Pabdeh formations have distinctive oil biomarker fingerprints. The bitumen from the Kazhdumi Formation has a high proportion of diasteranes relative to steranes, high proportions of C27 steranes and high C29/C30 hopane and high C30/C32+C33 hopane ratios. Bitumen from the Pabdeh Formation has low proportions of diasteranes, higher proportions of C29 steranes and lower C29/C30 hopane and high C30/C32+C33 hopane ratios. In terms of biomarker characteristics, the Bangestan oil are between the two groups, but contain biomarkers (alyklated trimethylbenzenes) that are not found within the Kazhdumi samples investigated during this study. However, the bulk δ13C isotope composition of the Bangestan oil fractions is a very conclusive match to the Kazhdumi and not the Pabdeh to any significant extent (Bordenave and Hegre, 2010). The apparent contradiction between biomarker and δ13C isotope data is not irreconcilable, because biomarkers typically comprise a quantitatively small proportion of oil. Other oil samples share biomarker fingerprints with the Bangestan oils or with the Kazhdumi.

The mixed biomarker-fingerprint of the Bangestan oils can be explained by one of two mechanisms; the in-reservoir mixing of multiple charges from different source kitchens or the acquisition of a mixed biomarker signal during oil migration (Peters et al., 2005). The only supporting evidence for in-reservoir mixing is the slightly lighter δ13C isotope composition of some of the polar constituents of the Bangestan oil that match those found in deeper oil reservoirs (Asadi Mehmandosti, 2011); although even in this instance most samples had resin and asphaltene δ13C isotope compositions that match the Kazhdumi. For a Pabdeh-biomarker fingerprint to be acquired during the migration of a Kazhdumi oil charge, the migration pathway would have to cross the Gurpi Formation and yet ultimately lead to the Bangestan reservoir. At this time subsurface data on the geological structure toward the flanks of the Marun anticline is not available, thus the feasibility of this scenario is hard to evaluate. Both scenarios point to a more complex filling history than may initially have been recognized and raise a number of questions; for example under what situations the sealing capacity of the Gurpi Formation is breached?

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**Figure Caption**

Figure 1. A: General location map of the Middle East region; B: Location map of the oil and gas fields in the Zagros foothills and contiguous offshore (after Bordenave and Hegre, 2005); C: Location of wells A-Q from which samples were collected..

Figure 2. Schematic stratigraphy and source rocks–reservoir–seal relationship for the Dezful Embayment and neighboring areas. The main source rocks are indicated by green flags and marginal ones by white flags; reservoirs (Res), and seals are also indicated (after Bordenave and Burwood, 1995).

Figure 3. The positions of studied samples on the Van-Krevelen diagram (Peters, 1986; Peters et al., 2005). Kazhdumi and Pabdeh samples show Type II kerogens; Gurpi samples indicate mixed type II/III kerogens.

Figure 4. The plot of Production Index vs. Tmax. This diagram shows that organic matter maturity of Pabdeh and Gurpi with the average of Tmax < 435 ºC are less than Kazhdumi samples (Modified from Peters, 1986).

Figure 5. Variation of Tmax and Production Index (PI) versus depth. It can be seen that Tmax and PI increased with increasing depth.

Figure 6. Selected GC-FID and GC-MS chromatographs of the saturate fraction of Bangestan oil from the Marun Oilfield.

Figure 7. selected GC-MS chromatographs of the aromatic fraction of Bangestan oil from the Marun Oilfield. DBT: di-benzothiophenes; MDBT: methyl-dibenzothiophenes; DMDBT: dimethyl dibenzothiophenes; P: phenanthrene; MP: methyl phenanthrene

Figure 8. Different biomarker parameters plotted versus depth for extracts source rocks. Thermal maturities increased from Pabdeh to Garau samples with increasing burial and depth.

Figure 9. Cross plot of A: C29ααα S/(S+R) Sterane, B: Dia 27S+R/(dia27S+R+C29ααα), C: C21/(C29+C21) Sterane, D: C29/C27 Sterane (αββ20R), E: C23TT/(ETT+C23TT), F: MPI and G: C20/C28 R triaromatic steroids as thermal maturity parameters versus Tmax.

Figure 10. Cross plot of Ts/ (Ts+Tm) versus C29αββ/ (αββ + ααα) . Ts/Ts+Tm parameter would suggest that source rocks especially Kazhdumi and Garau formations in the Marun region, are at the point of peak oil generation.

Figure 11. Cross plot of Dia 27S+R/(Dia27S+R+ C29 ααα) versus C30/C32+C33 Hopanes and C29/C30 Hopanes. Oil samples share their biomarker between Kazhdumi and Pabdeh samples and more near to Pabdeh.

Figure 12. Selected mass chromatograms on m/z=134, Alkylated trimethyl benzenes. Kazhdumi samples proportionally less of this biomarker. Carbon number is shown above peak.

1. Corresponding author: Tel.: +98 21 88827385;

*E-mail address*: e.asadi@khu.ac.ir (E. Asadi Mehmandosti). [↑](#footnote-ref-1)