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FULL LENGTH ARTICLE

Source rock evaluation and organic geochemistry of Belayim Marine Oil Field, Gulf of Suez, Egypt



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KEYWORDS

Source rock evaluation; Organic geochemistry; Rock Eval Pyrolysis; Belayim Marine Oil Field; Gulf of Suez **Abstract** Geochemical evaluation of Belayim Marine Oil Field using TOC and Rock Eval Pyrolysis investigations for a total of 19 cutting samples (9 samples covering (Nubia-B Formation) from well BM-57, and 10 samples covering (Nubia-A, B Formations) from well BM-65) was performed. Furthermore, geochemistry analyses of two crude oil samples from Wells BM-29 and BM-70, which are recovered from the Upper Rudeis Formation were performed. The BM-70 oil sample is recovered by Drill Steam Testing, while the BM-29 oil sample is taken from the flow output. Moreover, the oil samples were subjected to GC/GC-MS analysis (Biomarker) by StratoChem Company.

In general, TOC analyses showed that the Nubia-A and B formation sediments are fairly immature compared to good source rocks with very high Hydrogen Index indicative of kerogen type II. The geochemical investigations of two oil samples indicate that the Upper Rudeis oil of Belayim Marine was derived from a marine carbonate rich source, which is relatively rich in algal organic matter and has moderate sulfur content. The maturity of the analyzed oils (about 0.75% R0) falls short from the stage of peak hydrocarbon generation which is known to be reached at about 0.85% R0.

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1. Introduction

The Gulf of Suez represents the most interesting oil provinces in Egypt; it is divided into three tectonic zones separated by accommodation and transfer zones. Most of them are interesting such as oil exploration and production. The main tradi-

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tional play concept is represented by structurally high horst and tilted fault blocks. The Belayim Marine Field is located in east central part of the Gulf of Suez which resembles the central fields in their models, tectonics and petroleum system. Large numbers of exploratory and development wells were drilled through the long history of production and tested for this conventional play concept (Figure 1).

Many studies have been done on the Gulf of Suez province for the purpose of source rock evaluation. Among these studies are [1-7]. Younis concluded that the Black Shale of

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Figure 1 (a) Gulf of Suez Basin location map showing study area, Belayim Marine Oil Field [22]. (b) Study area Wells location map.



Figure 2 Tectonic setting and structural framework map [22].

the Nubia-B is considered as the mature potential source rock of the Nubia reservoir [7].

The main source rocks are located in the Pre Miocene succession; they are represented by fine clastics and carbonates belonging to the Nubia-B Formation (Carboniferous), brown limestone of the DAWI Formation (upper Cretaceous), ESNA shale Formation (Paleocene) and the THEBES carbonate Formation (Eocene). The secondary source rocks are represented by the Middle Miocene fine clastic and shale in Kareem, Rudeis, and Belayim formations. Thebes and Dawi formations are the main source rocks, the average TOC is 0.5–2 wt%, with mainly oil-prone type II kerogen.

With the increasing discovery of shale oil plays, rock and fluid heterogeneities within these plays are becoming evident. In addition to variations in source facies differences in thermal maturity over local areas are also responsible for some of the observed heterogeneities in fluid types. Therefore accurate determination of thermal maturity variations provides an inexpensive technique that can be used in high grade acreage and to determine where better quality oils are easier to produce.

The study area includes wells (BM-70, BM-65, BM-57, BM-36, BM-24, BM-23, 113-M-34, and 113-M-27).

2. Lithostratigraphy and structural framework

The lithostratigraphic units in the Gulf of Suez can be subdivided into three sequences: a prerift succession (pre-Miocene or Paleozoic–Eocene), a synrift succession (Oligocene–Mio-



Figure 3 Litho-stratigraphic column of the Belayim Marine Oil Field [22].

cene), and a postrift succession (post-Miocene or Pliocene-Holocene) (Figure 2). These units vary in lithology, thickness, distribution, depositional environment, and its hydrocarbon content. Geological and geophysical data show that the northern and central Gulf of Suez consist of several narrow, elongated depositional troughs, whereas the southern part is dominated by a tilt-block terrane, containing numerous offset linear highs (Figure 3).

The Belayim Marine is a NW–SE trending anticline with a main eastern fault with 2400 m displacement.



Figure 4 Geochemical evaluation of NUBIA-B Formation in the Belayim Marine Field Wells: BM-65 & BM-57. (A) TOC versus depth profile (B) Rock-Eval S2 versus depth (C) Rock-Eval Tmax versus depth (D) Modified Van Krevelen diagram showing the kerogen type of the formation.

Major prerift and synrift source rocks have the potential to yield oil and/or gas and are mature enough in the deep kitchens to generate hydrocarbons.

The reservoirs can be classified into prerift reservoirs, such as the Precambrian granitic rocks, Paleozoic-Cretaceous Nubian sandstones, Upper Cretaceous Nezzazat sandstones and the fractured Eocene Thebes limestone; and synrift reservoirs, such as the Miocene sandstones and carbonates of the Nukhul, Rudeis, Kareem, and Belayim formations and the sandstones of South Gharib, Zeit, and post-Zeit. The majority of oil fields in the region incorporate multiple productive reservoirs. Miocene evaporites are the ultimate hydrocarbon seals, whereas the shale and dense limestones of the prerift and the synrift stratigraphic units are the primary seals. Structural, stratigraphic, and combination traps are encountered in the study area.

There are 11 sand pay zones (one of which a flint-limestone conglomerate) form the South Gharib formation to Rudeis formation, between 1700 and 2786 m depth; the sandstones are very porous and permeable (porosity = 21-25%, $K \le 1000$ mD). In the Belayim Marine the Miocene traps are around a pre-Miocene block tilted NE, resting unconformably on Carboniferous "Nubia" on the west side, and on Late Cretaceous–Eocene rocks in the east side. The production is from sandstones in Belayim, Rudeis, and Cenomanian (Raha Formation)–Turonian (Wata Formation) sections, [8].



Figure 5 NUBIA-B Formation Source rock assessment, the Belayim Marine Field Wells: BM-65 & BM-57. (A) HI versus TOC according to log-log plot of [23]. (B) (S1 + S2) versus TOC according to log-log plot of [24]. (C) Distribution of source rock potential according to the S2 versus TOC log-log plot of [24]. (D) Maturation and nature of the hydrocarbon products according to the Tmax versus production index (PI) plot of [25].

Mostafa concluded that the organic rich Upper Senonian DAWI Formation brown limestone and Lower Eocene Thebes Formation carbonates are among the essential source rocks for generation of the hydrocarbon in the Gulf of Suez [5]. Abd El-Baki explained the depositional and stratigraphical history of the Gulf of Suez in three stages, namely: a pre- Carboniferous-Eocene, Lower Miocene and Middle/Upper Miocene [9]. The first stage is characterized by its hydrocarbon reservoir, the second by its source and reservoir behavior and the third close the depositional history of the Gulf of Suez. Carboniferous is characterized by relative thick black shale of the Nubia-B. This interval is highly indurated as deduced from the drilling information. Some intervals below and above the Nubia-B are hydrocarbon pay zones.

A thick Jurassic sequence (Nubia-A formation) overlays the unconformable carboniferous (Nubia-B formation) and is formed of carbonate and marls. Cenomanian (Raha formation) unconformable overlays the Jurassic and is mainly formed of carbonate facies with some intercalations of shale. On the top of Cretaceous, the Eocene limestone was deposited under marine conditions. Up from Eocene carbonate and by the beginning of Oligocene/Miocene period the tectonic development of the dynamic Gulf of Suez has dominated. Miocene facies are significant with source and reservoir rocks. They are either marine or non-marine facies. Kerogen is formed in the early burial stage from decomposition of plant and algal debris accumulated under reducing conditions of environment in the sediments. Beyond a temperature of 750 °C [10], Kerogen begins to transform into different modes of hydrocarbon under adequate time span. Liquid oil is first formed during kerogen transformation (catagenesis stage), followed by wet and then dry gas (metagenesis stage).



Figure 6 Geochemistry log of well BM-57.

The Rudeis Formation is 575 m thick. It is mainly composed of sandy and highly calcareous fossiliferous shales, and marls referred to as the Globigerina marls, as well as sandstone [11]. The basal part of the Rudeis Formation contains occasional thin yellowish gray massive sandy limestones. The formation contains high ratios of planktonic and benthonic species [12] and belongs to the Globigerinoides trilobus and Globigerinoides sicanus/Praeorbulina glomerosa foraminiferal zones [13,14].

The Rudeis Formation also contains nannoplankton of [15,16] zones NN3–NN4. Its age is assigned to the Early Miocene (early–middle Burdigalian) [12,14,17,18].

The Rudeis Formation is considered to contain the richest oil source rocks, deposited under most favorable structural conditions ([11,19]).

3. Methodology

Data of the analytical techniques; Total Organic Carbon (TOC) and Rock-Eval Pyrolysis for the analyzed samples are shown in Table 1. The analyzed samples include a total of 19 samples 9 samples covering interval 3182-3260 m TVDss from well BM-57 and 10 samples covering interval 3207–3339 m TVDss from well BM-65.

The wells were located in the Belayim Marine Oil Field, Gulf of Suez, Egypt. All samples were collected from Nubia-B member of carboniferous age, and were washed with solvent in order to eliminate the effect of contamination by oil-based mud and then determine Total Organic Carbon (TOC) and Rock-Eval Pyrolysis.



Figure 7 Geochemistry log of well BM-65.

The organic richness is determined by measuring the quantity of organic carbon in weight % (TOC), while S1, S2 and S3 are obtained from Pyrolysis data as S1 is the release of free hydrocarbon at about 300 °C, S2 is the percentage of the cracked hydrocarbons during Pyrolysis at maximum temperature Tmax, while S3 is the release of organically bound CO2 at temperatures ranging from 300 to 550 °C (Cornford 2005). The hydrogen and oxygen indices (HI, OI) can be determined from TOC and Rock-Eval Pyrolysis data, where (HI, OI) is equivalent to H/C ratio and O/C ratio in the kerogen, respectively.

Both indices are used in the identification of the kerogen type. Also, the Production Index (PI) is equal to S1/(S1 + S2). The Potential Yield (PY) = (S1 + S2) and the Transformation Index (TI) = S1/TOC are important parameters in assessing the source potential. The amount of kerogen is

determined as the total organic carbon (TOC), measured as weight percentage of the rock, and it can be described as poor, fair, good, very good, or excellent depending on the weight percentage of TOC.

Commonly, a poor source rock has TOC values below 0.5 (wt%) while a fair source ranges from 0.5 to 1 (wt%), the good source rock has TOC values ranging from 1 to 2 (wt%), the very good source rock has TOC values ranging from 2 to 4 (wt%), and the excellent source rock has TOC values more than >4. The maturity can be measured by using the Rock-Eval Pyrolysis parameters since the mature source rock has Tmax values above 435 °C and PI values above 0.1 [20].

Geochemistry of two crude oil samples from Wells BM-29 and BM-70, which are located within the Belayim Marine Field of the mid-eastern section of the Gulf of Suez, Egypt; are analyzed. The two samples are recovered from the Upper Rudeis Formation, the BM-70 oil sample is recovered by DST from the interval 3450–3469 m, while the BM-29 oil sample is taken from the flow output and recovered from the interval 2592–2774 m.

The applied analytical methods include API gravity determination, Liquid chromatography whole oil gas chromatography (LC), detailed C6 & C7 gas chromatography (C7-GC), gas chromatography–mass spectrometry (GC–MS) of the saturates and aromatics, and stable carbon isotope determination of the saturate/aromatic fractions and the determination of sulfur content and vanadium & nickel concentrations.

4. Result and discussion

4.1. Source rock assessment for wells BM-57 and BM-65

4.1.1. Well BM-57

Four samples from 3181 m to 3204 m TVDss contain rocks with average to very high organic contents (TOC 0.90–2.62%) and fair to good potential to generate oil and gas, at the present level of thermal maturity (Pyrolysis S2 yields 2.25-7.03 mg HC/g rock and HI 211-268 mg HC/g TOC) (Table 1).

The remaining analyzed rocks have high to very high organic contents (TOC 1.40–2.60%), their poor hydrocarbon generating potential, (Pyrolysis S2 1.24–1.88 mg HC/g TOC), and generally low HI (HI 67–117), indicated that these rocks could be considered as non source (Figures 4–6).

4.1.2. Well BM-65

Source rock assessment for the organically rich rock intervals from 3276 to 3279 m TVDss, 3285–3288 m TVDss, and 3300–3315 m TVDss (TOC 1.27–1.43%) appears to have fair potential for oil and gas generation, at the present level of thermal maturity (Pyrolysis S2 2.70–3.74 mg/g and HI 189–281). the remaining analyzed rocks have poor potential for hydrocarbon generation (Pyrolysis S2 1.33–2.10 mg/g), considered as non-source (Figures 4, 5 and 7).

4.2. Kerogen composition and thermal maturity for Wells BM-57 and BM-65

4.2.1. Well BM-57

Thermal maturity assessment for the analyzed interval from BM-57 well was based on vitrinite reflectance (R0) measurements, Thermal Alteration Index (TAI) and unstructured lipids texture.

The analyzed samples contain both marine and terrestrial organic matter with variable but nearly equal proportions. The lipids are mostly unstructured with some (up to 15%) structured liptodetrinite. The humic components include both ordinary vitrinite macerals and lipid-rich vitrinite with the latter generally decreasing with depth.

Terrestrial organic matter in the first four samples (3181– 3231 m TVDss) is dominated by lipid-rich vitrinite which is too roughly textured for R0 measurements having only limited number of indigenous macerals for maturity calculations. Consequently the R0 values (0.32–0.42% R0) appear to be strongly suppressed and questionable.

Table 1	Total Organic Carbon	(TOC) and Rock-Eval Pyrc	plysis data for the analyzed Sampl	les.

Age	Rock unit	Depth	Lithology	TOC	S 1	S2	S 3	Tmax	HI	OI	PI	ΤI	PY
Well: BM-65: Pyrc	olysis on Sam	ples TOC > 0	.5%										
		M (TVDss)		wt%	mg/g	mg/g	mg/g	deg (°C)					
Lower cretaceous	Nubia-A	3208	Shale & sandstone	0.6	0.26	1.59	0.86	429	265	143	0.14	0.43	1.85
		3241	Shale & sandstone	0.6	0.2	1.84	0.67	430	307	112	0.10	0.33	2.04
		3250	Shale & sandstone	0.56	0.13	1.33	0.59	429	238	105	0.09	0.23	1.46
		3259	Shale & sandstone	1.03	0.56	1.72	0.89	425	167	86	0.25	0.54	2.28
	Nubia-B	3277	Sandstone & shale	1.33	0.43	3.74	0.89	432	281	67	0.10	0.32	4.17
		3286	Sandstone & shale	1.27	0.38	2.88	0.96	432	227	76	0.12	0.30	3.26
		3298	Sandstone & shale	1.43	0.38	2.7	0.82	429	189	57	0.12	0.27	3.08
		3316	Sandstone & shale	1.24	0.27	1.6	0.85	428	129	69	0.14	0.22	1.87
		3328	Sandstone & shale	2.1	0.27	1.64	0.84	425	78	40	0.14	0.13	1.91
		3337	Sandstone & shale	4.1	0.56	2.1	0.83	427	51	20	0.21	0.14	2.66
Well: BM-57: Pyre	olysis on Sam	$oples \ TOC > 0$.5%										
	Nubia-B	M (TVDss)		wt%	mg/g	mg/g	mg/g	deg (°C)					
		3182	Shale & sandstone	0.9	0.33	2.25	0.79	428	250	88	0.13	0.37	2.58
		3189	Shale & sandstone	2.62	0.83	7.03	1.35	427	268	52	0.11	0.32	7.86
		3196	Shale & sandstone	2.32	0.55	4.9	1.81	431	211	78	0.10	0.24	5.45
		3202	Shale & sandstone	1.44	0.33	3.62	1.41	435	251	98	0.08	0.23	3.95
		3217	Shale & sandstone	1.5	0.24	1.76	1.16	427	117	77	0.12	0.16	2
		3231	Shale & sandstone	1.4	0.22	1.63	0.93	433	116	66	0.12	0.16	1.85
		3247	Shale & sandstone	2.6	0.24	1.88	0.95	430	72	37	0.11	0.09	2.12
		3253	Shale & sandstone	2.4	0.24	1.61	0.85	427	67	35	0.13	0.10	1.85
		3260	Shale & Sandstone	1.46	0.15	1.24	0.71	430	85	49	0.11	0.10	1.39

S1 & S2 values are in mg hydrocarbon/g rock, S3 mg CO2/g rock, Tmax in $^{\circ}$ C, HI hydrogen index (mg hydrocarbon/g TOC), OI Oxygen Index (mg CO2/g TOC), PI production Index. (S1/S1 + S2), TI Transformation Index (S1/TOC), and PY Potential Yield (S1 + S2).



Figure 8 Bulk composition plot of the Belayim Marine oils.

The samples from 3259 to 3262 m TVDss, contain organically-rich rocks (TOC 1.46%) and abundant vitrinite with (R0 2.18%).

TAI values mostly range from 2 + to 3 + for unstructured lipids ($\approx 0.7-1.7\%$ R0) indicating a lower maturity for the analyzed interval (3181–3262 m TVDss) more than that shown by R0 values.

The massive to micronized texture and color of the unstructured lipids suggest a slightly higher maturity than that derived from TAI values.

The analyzed carboniferous rocks in well BM-57 are past the oil on the floor defined by 1.35% R0, and has probably reached maturities grater than 1.7% R0.

4.2.2. Well BM-65

The analyzed interval showed both marine and terrestrial organic matter, with the marine component dominating in most samples and decreasing generally with depth. The marine organic matter is mainly composed of unstructured lipids in much lesser amount (up to 5%), structured liptodetrinite, and the trace of alginite in one sample (3208– 3211 m TVDss).

The humic component includes both ordinary vitrinite macerals and lipid-rich vitrinite with latter dominating in all samples.

Terrestrial organic matter in the first four samples (3208– 3300 m TVDss) is dominated by lipid-rich vitrinite which is too roughly textured for R0 measurements having only limited number of indigenous macerals for maturity calculations. Consequently the R0 values (0.34–0.41% R0) appear to be strongly suppressed and questionable.

The samples from 3336 to 3339 m TVDss, contain organically-rich rocks (TOC 4.10%) and abundant vitrinite with (R0 2.15%).

Based on the texture of unstructured lipids together with unstructured TAI values, this section appears to have a thermal maturity similar to that of BM-57 well.

4.3. Biomarker application

Geochemistry of two crude oil samples from the Wells BM-29 and BM-70, which are located within the Belayim Marine Oil Field of the mid-eastern section of the Gulf of Suez, Egypt; are analyzed. The two samples are recovered from the Upper Rudeis Formation, the BM-70 oil sample is recovered by DST from interval 3450–3469 m, while the BM-29 oil sample is taken from the flow output and recovered from the interval 2592–2774 m.

The two oil samples are highly similar in composition and represent medium mature oils, and were derived from a common marine source which is relatively rich in carbonate and contains algal organic matter.

The two oil samples indicated may be regarded as fairly typical Gulf of Suez oils. The used analytical methods include



Figure 9 Carbon isotope compositions of aromatics vs. saturate for the Belayim Marine Fields, after [26].



Figure 10 Oil gas chromatograms of Rudeis Formation in Well BM-29.



Figure 11 Oil gas chromatograms of Rudeis Formation in Well BM-70.



Figure 12 Relationship between isoprenoid n-alkanes showing source and depositional environments [27]. Cross plot (Pr/n-C17 vs. Ph/n-C18) of the Belayim Marine Oils.



Figure 13 Sulfur content (wt%) vs. Pristane/Phytane ratio [28]. The source of the Belayim Marine Oils.



Figure 14 Toluene/n-heptane vs. n-heptane/methylcyclohexane plot (Thompson [31]). Light (C7) hydrocarbon data from the Belayim Marine oils. C7 based plots suggest that the analyzed oils are original and unaltered. (P1) nC7 n-heptane, (P2) 2MH + 3MH (2-methylhexane + 3-methylhexane), (P3) 22DMP + 23DMP + 24DMP + 33DMP + 3EP (2,2-dimethylpentane + 2,3-dimethylpentane + 2,4-dimethylpentane + 3,3-dimethylpentane).



(P1) nC7 n-heptane, (P2) 2MH+3MH (2-methylhexane + 3-methylhexane), (P3) 22DMP+23DMP+24DMP+33DMP+3EP (2,2-dimethylpentane+ 2,3-dimethylpentane+ 2,4-dimethylpentane + 3,3-dimethylpentane).



Figure 15 Two C7-based plots suggesting that the Belayim Marine Oils have not been affected by biodegradation.



Figure 16 Ring preference plot at C7. After [29], the ends of members are isoalkanes (3RP), cyclopentanes (5RP), and cyclohexanes (6RP). It shows depositional environments of the hydrocarbon source of the Belayim Marine oil from Wells BM-70 and BM-29.

API gravity determination, Liquid chromatography whole oil gas chromatography (LC), detailed C6 & C7 gas chromatography (C7-GC), gas chromatography-mass spectrometry (GC–MS) of the saturates and aromatics, and stable carbon isotope determination of the saturate/aromatic fractions and the determination of sulfur % and V & Ni concentrations (The V/Ni ratios are used to differentiate between the crude oils derived from different source rocks [7].



Figure 17 Expulsion temperature of the Belayim Marine Oils, as derived from C7 compounds. This is support the maturity estimated from the LC and GC data, where the calculation parameters (It) natural log of (24DMP/23DMP + 2.637/0.227), and (InZ) natural log of P3 over N2.



Figure 18 Distribution of steranes C27, C28 and C29 in triangular diagram of [30] from GC/MS data showing organic Facies variations.

4.4. Oil characterization

The two oil samples are similar and show very little geochemical differences. Gross bulk compositions are similar and show that oils are dominated by saturates (40.6-47.7%), with moderate amounts of aromatics (30.6-33.6%), NSO compounds (concentration 15.3%), and Asphaltene (6.4-10.5%) (see Tables 2–11).

Sulfur content for both samples is almost identical (concentration 2%), while the BM-70 oil contains almost twice as much V and Ni concentrations (V = 96 ppm & Ni = 19 ppm) compared to the BM-29 oil (V = 54 ppm & Ni = 10 ppm), although their V/Ni ratios (5.1-5.4) are nearly the same.

The bulk oil composition, the moderately low saturate/aromatic ratios (1.2–1.6), and the API gravity values (25–29°) are all suggestive of moderate thermal maturity.

Both oil samples have nearly identical $\delta 13C$ aromatic and $\delta 13C$ saturate values of -28.6% & -28.7% and -28.0% & -28.2%, the values suggest that the analyzed oils are derived from a marine organic matter source.

Note that these values are also very similar to those typical of Gulf of Suez oils [21].

The whole oil gas chromatograms of two oil samples show a very similar n-alkane pattern, with a regular decrease in the heavier compounds, and relatively higher concentration of the lighter (n-C < 15) compounds.

The geochemical parameters of isoprenoid hydrocarbons, such as pristane (Pr) and phytane (Ph), could be taken as an indication of the depositional environments of the crude oils. The Pr/n-C17, Ph/n-C18 and Pr/Ph ratios of both samples are 0.47–0.46, 0.59–0.70 and 0.83–0.72 indicating that the oils are derived from a carbonate rich source rock, deposited in reducing marine environment at a modest thermal maturity (Figures 10–13).

This is in agreement with the bulk composition and stable carbon isotope data (Figures 8 and 9).

On the basis of the light hydrocarbon (C7) composition, both oil samples show evidence of enrichment in n-Heptane and may have suffered some water washing (Figure 15).

 Table 2
 Sulfur content, V ppm, NI ppm, and API gravity data.

Sample identification										
Sample No.	Well name	Formation	Depth (m)	Sulfur wt (%)	V (ppm)	NI (ppm)	API			
1	BM-29	Rudeis	2592-2774	1.9	54	10	29			
2	BM-70	Rudeis	3450-3469	2	96	19	25			

Table 3 Liquid chromatography and stable carbon isotope (δ 13C) data.

Sample identif	ication			Liquid chromatography					
Sample No.	Well name	Formation	Depth (m)	Saturates (%)	Aromatics (%)	NSO (%)	Asphaltene		
1	BM-29	Rudeis	2592-2774	47.7	30.6	15.3	6.4		
2	BM-7 0	Rudeis	3450-3469	40.6	33.6	15.3	10.5		
Sample identif	ication			Stable carbon isotopes					
Sample No.	Well name	Formation	Depth (m)	Saturates (%)		Aromatics (%)			
1	BM-29	Rudeis	2592-2774	-28.6		-28.0			
2	BM-70	Rudeis	3450-3469	-28.7		-28.2			

 Table 4
 Gas chromatography of C6 and C7 compounds of the Belayim Marine Wells BM-70 and BM-29.

Sample identification		Gas chromatography of C6 & C7			
Sample No.	Well name	Formation	Depth (m)	Total C6 area	Total C7 area
1	BM-29	Rudeis	2592-2774	471,315	706,915
2	BM-70	Rudeis	3450-3469	457,409	584,102

Table 5 C7 gas chromatography calculated parameters of the Belayim Marine Wells BM-70 and BM-29.

Sample identification					Thompson compositional ratios					
Well name	Formation	Depth (m)	Н	F	В	Ι	А	R		
BM-29 BM-70	Rudeis Rudeis	2592–2774 3450–3469	31.9 32.29	1.73 2.01	0.48 0.35	1.41 1.37	0.18 0.09	4.17 4.26		
	Well name	Formation	Depth (m)	P1	P2	P3	It	Primesum		
	BM-29 BM-70	Rudeis Rudeis	2592–2774 3450–3469	27.83 28.98	18.32 19.79	5.20 5.51	4.89 4.76	0.94 0.92		
	Cation Well name BM-29 BM-70	cation Well name Formation BM-29 Rudeis BM-70 Rudeis Well name BM-29 BM-70 BM-70	cationWell nameFormationDepth (m)BM-29Rudeis2592–2774BM-70Rudeis3450–3469Well nameFormationBM-29RudeisBM-29RudeisBM-70Rudeis	Thompson ccWell nameFormationDepth (m)HBM-29Rudeis2592–277431.9BM-70Rudeis3450–346932.29Well nameFormationDepth (m)BM-29Rudeis2592–2774BM-70Rudeis3450–3469	Thompson compositionaWell nameFormationDepth (m)HFBM-29Rudeis2592–277431.91.73BM-70Rudeis3450–346932.292.01Well nameFormationDepth (m)P1BM-29Rudeis2592–277427.83BM-70Rudeis3450–346928.98	Thompson compositional ratios Well name Formation Depth (m) H F B BM-29 Rudeis 2592–2774 31.9 1.73 0.48 BM-70 Rudeis 3450–3469 32.29 2.01 0.35 Well name Formation Depth (m) P1 P2 BM-29 Rudeis 2592–2774 27.83 18.32 BM-70 Rudeis 3450–3469 28.98 19.79	Thompson compositional ratios Well name Formation Depth (m) H F B I BM-29 Rudeis 2592–2774 31.9 1.73 0.48 1.41 BM-70 Rudeis 3450–3469 32.29 2.01 0.35 1.37 Well name Formation Depth (m) P1 P2 P3 BM-29 Rudeis 2592–2774 27.83 18.32 5.20 BM-70 Rudeis 3450–3469 28.98 19.79 5.51	Thompson compositional ratios Well name Formation Depth (m) H F B I A BM-29 BM-70 Rudeis 2592–2774 31.9 1.73 0.48 1.41 0.18 BM-70 Rudeis 3450–3469 32.29 2.01 0.35 1.37 0.09 Well name Formation Depth (m) P1 P2 P3 It BM-29 BM-70 Rudeis 2592–2774 27.83 18.32 5.20 4.89 BM-70 Rudeis 3450–3469 28.98 19.79 5.51 4.76		

(H) Heptane, (F) Paraffinicity, (B) Aromaticity, (I) Isoheptane, (A) Aromaticity, (R) Paraffin Branching.(P1) nC7 n-heptane, (P2) 2MH + 3MH (2-methylhexane + 3-methylhexane),

 $(P3) \ 22DMP + 23DMP + 24DMP + 33DMP + 3EP \ (2,2-dimethylpentane + 2,3-dimethylpentane + 2,4-dimethylpentane + 3,3-dimethylpentane + 3,3-dimethylpenta$

Table	6	Organic	facies	and	depositional	environment	ratios
of the	wel	1 BM-29.					

GC-MS triterpanes steranes ratios	
C19 + C20 tricyclics/C23 Tricyclics	0.30
C24 tetracyclic/C26 tricyclics	0.67
C23 tricyclic/C24 tricyclic	1.92
C25 tricyclics/C26 tricyclics	1.28
C28 bisnorhopane/C30 HOPANE	0.03
C29 norhopane/C30 hopane	0.86
C30 diahopane/C30 hopane	0.02
C30 oleanane/C30 hopane	0.06
C30 30-norhopane/C30 hopane	0.08
Gammacerane/C30 HOPANE	0.1
Extended hopanes (%)	29.61
C35/C34 extended hopanes	1.10
Tricyclic terpanes/hopanes	0.54
Hopanes/steranes	1.77

Table 7Thermal maturity ratios of the well BM-29.

Maturity-dependent ratios	
Ts/Tm	0.46
C29 Norhopane (29 Ts)/C29 Norhopane	0.13
C30 Diahopane/C30 Hopane	0.02
Diasteranes %	24.9
Tricyclic Terpanes/Hopanes	0.54
Short-chain Steranes	9.8

According to the ring preference diagram, the Belayim marine oils show very little terrestrial contribution and appear to be generated from a predominantly marine organic matter source (see Figures 14, 16, and 18). In addition to the cross plot of Figure 17 indicates an It about 4.75 and an expulsion temperature of 115 °C for the oils, which suggest that their thermal maturity is about $\rightarrow 0.75\%$ R0.

Gas chromatography–Mass Spectrometry (GC–MS), and Biomarker parameters provide additional information on the source characteristics and thermal maturity of the oils (see Figures 16–18).

Note that the GC-MS results of two oil samples are quite similar; corroborating the idea of oils shares a common origin. The salient GC-MS features are as follows:

- 1- Low C19 + C20 Tricyclics/C23 Tricyclic ratio (0.28– 0.30).
- 2- A low predominance of C27 sterane over C29 sterane (~ 1.10) .
- 3- Clear predominance of C27 aaa (20R) sterane over C29 aaa (20R) sterane (1.94–1.62).
- 4- High C23 Tricyclic/C24 Tetracyclic ratio (~3.80).
- 5- High proportion of the extended C31–35 Hopanes $(\sim 30\%)$ distribution.
- 6- High C35/C34 ratio (1.10–1.04).
- 7- Low Short-Chain Steranes % (9.8-94).
- 8- Very low P/DBT % (0.7–0.6).
- 9- Moderately low Short-Chain TSA % (15.1-11.4).
- 10- Moderate MPI 1 values (0.53–0.59).
- 11- Moderate MDR values (2.11–1.87).

These features suggest that the source rock consists mostly of marine/algal organic matter and is presumably carbonate rich, and the maturity of the analyzed oils falls short from the stage of peak hydrocarbon generation which is known to be reached at about 0.85% R0.

The ratio of trisnorhopane/trisnorneohopane (Ts/Tm) is considered to be a facies and depositional environmental parameter of the relevant source rocks.

Table 8 Gas chromatography-mass spectrometry BM-29.

Gas chromatography - mass spectrometry aromatic sterane and 2- & 3- ring aromatic hydrocarbon report petrobel DGSI project:99/4627

Sample No. 1 Other ID: BM-29)
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Monoar	omatic (MA) steranes $(m/z \ 253)$			
No.	MA	Compound name	Ret time	Area	Area (%)
1	А	5b C ₂₇ MA-sterane (20S)	84.432	52,725	4.99
2	В	dia C ₂₇ MA-sterane (20S)	84.586	57,573	5.45
3	С	5b C_{27} MA-sterane (20R) + dia C_{27} MA-sterane (20R)	86.429	91,509	8.67
4	D	5a C ₂₇ MA-sterane (20S)	86.620	34,600	3.28
5	Е	5b C_{28} MA-sterane (20S) + dia 5b C_{28} MA-sterane (20S)	87.165	216,634	20.52
6	F	5a C ₂₇ MA-sterane (20R)	88.725	24,566	2.33
7	G	5b C_{28} MA-sterane (20S)	88.968	54,054	5.12
8	Н	5b C_{28} MA-sterane (20R) + dia C_{28} MA-sterane (20R)	89.214	189,359	17.93
9	Ι	5b C_{29} MA-sterane (20S) + dia C_{29} MA-sterane (20S)	89.432	116,750	11.06
10	J	$5a C_{29}$ MA-sterane (20S)	91.085	24,858	2.35
11	K	5a C_{28} MA-sterane (20R)	91.464	80,461	7.62
12	L	5b C_{29} MA-sterane (20R) + dia C_{29} MA-sterane (20R)	91.644	81,831	7.75
13	М	5a C ₂₉ MA-sterane (20R)	94.034	31,037	2.94
Triaron	natic (TA) S	$Teranes (m/z \ 231)$			
No.	TA	Compound name	Ret time	Area	Area (%)
1	А	C ₂₉ TA-sterane	78.780	269,123	8.13
2	В	C ₂₁ TA-sterane	81.930	232,208	7.02
3	С	C_{26} TA-sterane (20S)	93.785	131,434	3.97
4	D	C_{26} TA-sterane (20R) + C_{27} TA-sterane (20S)	96.404	1,038,647	31.38
5	Е	C_{28} TA-sterane (20S)	98.761	524,388	15.84
6	F	C ₂₇ TA-sterane (20R)	99.981	709,095	21.43
7	G	C ₂₈ TA-sterane (20R)	103.372	404,626	12.23

Table 7 Gas chromatography-mass spectrometry Divi- 2	Table 9	Gas	chromatogra	iphy–mass	spectrometry	BM-29
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Gas chromatography-mass spectrometry aromatic sterane and 2- & 3-ring aromatic hydrocarbon report petrobel DGSI project:99/4627

Sample No. 1 Other id: BM-29						
Naphth	alenes		_			
No.	Ν	Compound name	Ion	Ret time	Area	Area (%)
1	А	2-Ethylnaphthalene	156	34.242	2,111,851	2.10
2	В	1-Ethylnaphthalene	156	34.300	1,460,939	1.46
3	С	2,6 + 2,7-Dimethylnaphthalene	156	34.948	13,427,512	13.38
4	D	1,3 + 1,7-Dimethylnaphthalene	156	35.640	1,455,917	14.50
5	E	1,6-Dimethylnaphthalene	156	35.833	17,120,794	17.06
6	F	1,4 + 2,3-Dimethylnaphthalene	156	36.678	4,338,723	4.32
7	G	1,5-Dimethylnaphthalene	156	36.788	5,742,970	5.72
8	Н	1,2-Dimethylnaphthalene	156	37.447	4,692,244	4.68
9	Ι	1,3,7-Trimethylnaphthalene	170	41.285	4,901,207	4.88
10	J	1,3,6-Trimethylnaphthalene	170	41.576	8,536,852	8.51
11	K	1,4,6 + 1,3,5-Trimethylnaphthalene	170	42.334	6,479,444	6.46
12	L	2,3,6-Trimethylnaphthalene	170	42.552	4,936,141	4.92
13	Μ	1,2,7 + 1,6,7 + 1,2,6-Trimethylnaphthalene	170	43.227	7,738,359	7.71
14	Ν	1,2,4-Trimethylnaphthalene	170	43.970	1,315,374	1.31
15	0	1,2,5-Trimethylnaphthalene	170	44.343	3,000,252	2.99
Phenan	threnes					
No.	Р	Compound name	Ion	Ret time	Area	Area (%)
1	А	Phenanthrene (P)	178	53.159	3,098,920	34.60
2	В	3-Methylphenanthrene (3-MeP)	192	58.296	971,530	10.85
3	С	2-Methylphenanthrene (2-MeP)	192	58.529	1,363,476	15.22
4	D	9-Methylphenanthrene (9-MeP)	192	59.298	2,006,675	22.41
5	Е	1-Methylphenanthrene (1-MeP)	192	59.522	1,515,253	16.92
Dibenza	othiophenes					
No.	DB	Compound name	Ion	Ret time	Area	Area (%)
1	А	Dibenzothiophene (DBT)	184	51.886	4,032,754	32.00
2	В	4-Methyldibenzothiophene (4-MeDBT)	198	56.519	4,120,260	32.69
3	С	3 + 2-Methyldibenzothiophene (3/2-MeDBT)	198	57.354	2,494,592	19.80
4	D	1-Methyldibenzothiophene (1-MeDBT)	198	58.275	1,954,515	15.51

Table 10 Gas Chromatography–Mass Spectrometry BM-70.

Gas chromatography-mass spectrometry aromatic sterane and 2- & 3- ring aromatic hydrocarbon report petrobel DGSI project:99/4627

Sample	No. 2 Other	f ID: BM-70			
Monoar	omatic (MA	1) steranes $(m/z \ 253)$			
No.	MA	Compound name	Ret time	Area	Area (%)
1	А	5b C ₂₇ MA-sterane (20S)	84.436	927,510	6.65
2	В	dia C ₂₇ MA-sterane (20S)	84.585	451,183	3.23
3	С	5b C_{27} MA-sterane (20R) + dia C_{27} MA-sterane (20R)	86.441	1,086,587	7.79
4	D	5a C ₂₇ MA-sterane (20S)	86.620	514,388	3.69
5	Е	5b C_{28} MA-sterane (20S) + dia 5b C_{28} MA-sterane (20S)	87.166	2,736,378	19.61
6	F	5a C ₂₇ MA-sterane (20R)	88.732	424,729	3.04
7	G	5b C_{28} MA-sterane (20S)	88.974	1,014,134	7.27
8	Н	5b C_{28} MA-sterane (20R) + dia C_{28} MA-sterane (20R)	89.231	2,332,086	16.71
9	Ι	5b C_{29} MA-sterane (20S) + dia C_{29} MA-sterane (20S)	89.453	1,406,977	10.08
10	J	5a C ₂₉ MA-sterane (20S)	91.090	400,399	2.87
11	K	$5a C_{28}$ MA-sterane (20R)	91.472	1,187,127	8.51
12	L	5b C_{29} MA-sterane (20R) + dia C_{29} MA-sterane (20R)	91.705	963,180	6.90
13	Μ	5a C_{29} MA-sterane (20R)	94.022	510,409	3.66
Triaron	natic (TA) si	teranes (m/z 231)			
No.	TA	Compound name	Ret time	Area	Area (%)
1	А	C ₂₉ TA-sterane	78.783	817,518	5.78
2	В	C ₂₁ TA-sterane	81.931	794,472	5.62
3	С	C ₂₆ TA-sterane (20S)	93.790	701,466	4.96
4	D	C_{26} TA-sterane (20R) + C_{27} TA-sterane (20S)	96.407	4,552,824	32.19
5	Е	C_{28} TA-sterane (20S)	96.760	2,242,865	15.86
6	F	C ₂₇ TA-sterane (20R)	99.986	3,244,549	22.94
7	G	C_{28} TA-sterane (20R)	103.377	1,788,587	12.65

Table 11	Gas chroma	tography–mass	spectrometry	BM-70.
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Gas chromatography-mass spectrometry aromatic sterane and 2- & 3-ring aromatic hydrocarbon report petrobel DGSI project:99/4627

Sample	No. 2 other	r id: BM-70				
Naphth	alenes					
No.	Ν	Compound name	Ion	Ret time	Area	Area (%)
1	А	2-Ethylnaphthalene	156	34.258	2,181,182	2.12
2	В	1-Ethylnaphthalene	156	34.330	1,289,330	1.25
3	С	2,6 + 2,7-Dimethylnaphthalene	156	34.965	11,210,268	10.88
4	D	1,3 + 1,7-Dimethylnaphthalene	156	35.652	12,847,131	12.47
5	Е	1,6-Dimethylnaphthalene	156	35.846	15,033,322	14.59
6	F	1,4 + 2,3-Dimethylnaphthalene	156	36.690	4,131,357	4.01
7	G	1,5-Dimethylnaphthalene	156	36.807	5,091,404	4.94
8	Н	1,2-Dimethylnaphthalene	156	37.464	4,548,810	4.41
9	Ι	1,3,7-Trimethylnaphthalene	170	41.298	5,908,715	5.73
10	J	1,3,6-Trimethylnaphthalene	170	41.587	10,550,709	10.24
11	K	1,4,6 + 1,3,5-Trimethylnaphthalene	170	42.347	8,272,438	8.03
12	L	2,3,6-Trimethylnaphthalene	170	42.565	5,857,897	5.69
13	М	1,2,7 + 1,6,7 + 1,2,6-Trimethylnaphthalene	170	43.266	9,964,077	9.67
14	Ν	1,2,4-Trimethylnaphthalene	170	43.983	1,911,788	1.86
15	0	1,2,5-Trimethylnaphthalene	170	44.356	4,232,811	4.11
Phenan	threnes					
No.	Р	Compound name	Ion	Ret time	Area	Area (%)
1	А	Phenanthrene (P)	178	53.163	3,037,960	27.22
2	В	3-Methylphenanthrene (3-MeP)	192	58.297	1,311,093	11.75
3	С	2-Methylphenanthrene (2-MeP)	192	58.530	1,830,340	16.40
4	D	9-Methylphenanthrene (9-MeP)	192	59.297	2,889,700	25.89
5	Е	1-Methylphenanthrene (1-MeP)	192	59.522	2,091,708	18.74
Dibenzo	othiophenes					
No.	DB	Compound name	Ion	Ret time	Area	Area (%)
1	А	Dibenzothiophene (DBT)	184	51.891	4,402,863	24.24
2	В	4-Methyldibenzothiophene (4-MeDBT)	198	56.522	6,370,973	35.08
3	С	3 + 2-Methyldibenzothiophene (3/2-MeDBT)	198	57.354	3,986,408	21.95
4	D	1-Methyldibenzothiophene (1-MeDBT)	198	58.274	3,401,056	18.73

5. Conclusions

In BM-57 well, the four analyzed samples from 3181 to 3262 m TVDss, contain rocks with the capacity for oil and gas generation at the present level of thermal maturity, and the remaining analyzed rocks are organically-rich and have poor hydrocarbon generating potential, and considered as non-source.

The analyzed interval contains both marine and terrestrial organic matter with variable but nearly equal proportions. All maturity parameters except Pyrolysis analysis Tmax values, suggest that the analyzed carboniferous rock in BM-57 well are past the oil floor (defined by 1.35%R0), and has probably reached maturities grater than 1.7% R0.

In BM-65 well, the analyzed intervals (3276–3279 m), (3285–3288 m), (3300–3315 m TVDss) appear to have fair potential for gas and oil generation, at the present level of thermal maturity. Similar to BM-57 well, all maturity parameters except Pyrolysis analysis Tmax values, suggest that the analyzed carboniferous rock in BM-65 well are past the oil floor (defined by 1.35% R0), and has probably reached maturities grater than 1.7% R0.

Source rock intervals in well BM-57 were detected from 3183 to 3209 m TVDss and from 3246 to 3262 m TVDss. While source rock intervals in well BM-65 were detected from 3325 to 3339 m TVDss.

The two oil samples from BM-29 and BM-70 have similar gross composition and have a common origin.

The oils have moderate sulfur content and were derived from a marine carbonate rich source, which is rich in algal organic matter. Maturity estimates suggest that these oils are probably generated at a maturity of about 0.75% R0.

The BM-29 and BM-70 oil samples appear to be fairly typical of the Gulf of Suez crude oils. Oil source correlations indicating that the oils in the reservoir rock are not derived from the Nubia-B source rock.

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