

Organic Geochemical Evaluation of Cretaceous Potential Source Rocks, East Sirte Basin, Libya

S. Abogbila*, M. Elkhajji
Tripoli University, Tripoli, Libya
Email: *Salem.abogbila@gmail.com

Received April 7, 2013; revised May 10, 2013; accepted June 8, 2013

Copyright © 2013 S. Abogbila, M. Elkhajji. This is an open access article distributed under the Creative Commons Attribution License, which permits unrestricted use, distribution, and reproduction in any medium, provided the original work is properly cited.

ABSTRACT

Cutting samples ($n = 93$) from the Sirte, Tagrifet, Rakb, Rachmat, Bahi Formations of Upper Cretaceous and Nubian Formation (Lower Cretaceous) derived from eleven wells (6C1-59, 6J1-59, 6R1-59, KK1-65, OO2-65, M1-51, KK1-65, B-96, B-95, B-99, E1-NC-59) locate in the Amal, Gialo, Nafoora, and Sarir Fields present in East Sirte Basin were analysed in the aim of their organic geochemical evaluation. A bulk geochemical parameters and evaluation of specific biomarkers by chromatography-mass spectrometry (GC-MS) implemented to find out a diversity of interbedded non-marine lithofacies including sandstones, siltstones, shales and conglomerates. Such rocks are good source and contain fair to good contented of organic matter passing in the course of very good, in which the excellent source rocks have organic carbon richness (TOC) reached to 5.16 wt%. The studied samples are ranged from gas to oil-prone organic matter (OM) of hydrogen index (HI) ranged between 115 - 702 mg HC/g TOC, related with gas prone (OM) of (HI) <150 and most beds contain oil-prone organic matter of (HI) > 300, associated with oxygen index (OI): 3 - 309 mg CO₂/g TOC indicate that organic matter is dominated by Type II/III kerogen. The maturity of these source rocks is variations ranges from mature to post-mature-oil window in the Sirte and Rachmat Formations, as inferred from the production index (PI: 0.07 - 1.55) and T_{max} and Ro% data (T_{max} : 425 - 440/Ro%: 0.46 - 1.38) and early to mid-stage maturities for the other formations. Low PI in some samples seems to imply that the most of the hydrocarbons have expelled and migrated from the rocks. Biomarker ratios of individual hydrocarbons in rock extracts ($n = 21$), were also used in order to investigate the samples' thermal maturity and palaeo depositional conditions. Pristine/Phytane ratios of 0.65 - 1.25 and dibenzothiophene to phenanthrene (DBT/P) ratios of 0.04 - 0.47 indicated Anoxic and suboxic conditions of depositional source rock. The origin of OM of the studied samples attributed to a marine algal source as indicated from the dominated by the C₂₇ and co-dominant C₂₈ homologues sterane in molecular composition distributions. The marine shale and carbonate lithofacies of rock samples were also indicated by high C₁₉TT/C₂₃TT ratio and low relative abundance of C₂₄TeT/C₂₃TT, consistent with their interpreted marine affinity. An organic geochemical evaluation pointed out that the Sirte Shale formation (Campanian/Turonian) is the main source rock in this petroleum area.

Keywords: Sirte Basin; Libya; Sirte Formation; Biomarkers; Potential Cretaceous Source Rocks of Sirte Basin

1. Introduction

Traditionally, Upper Cretaceous marine shales of the Sirte and Rachmat Formations have been identified as the main source rocks for hydrocarbons in the Sirte Basin, north central Libya [1,2] (**Figure 1**), with total organic carbon (TOC) contents ranging between 1% and 5% [3]. The main depression within a sedimentary in the East Sirte Basin is the Agedabia Trough (**Figure 1**) where the thickest development of the sedimentary sequence [4]. Petroleum system in the Agedabia Trough is sourced by the clastics of Lower Cretaceous age as primary reser-

voirs with stratigraphic section consists mainly fluvial and alluvial sandstones mostly of the Nubia, in addition to the upper Cretaceous (Campanian) shale bed particularly Sirte Shale is by far the dominant source rock [4-6]. Basin modelling [5] shows that in the southern part of the Agedabia Trough the Rachmat Formation entered the oil window during the mid-Eocene, whereas the Sirte Shale started generating oil in the late Eocene. In the Hameimat Trough, Upper Cretaceous marine shales of the Tagrifet Formation and the Rakb Formation (**Figure 2**) have been identified as potential source rocks and act as the seal for a number of the Sarir fields [7]. The Nubian Formation (non-marine Lower Cretaceous units) in this trough

*Corresponding author.

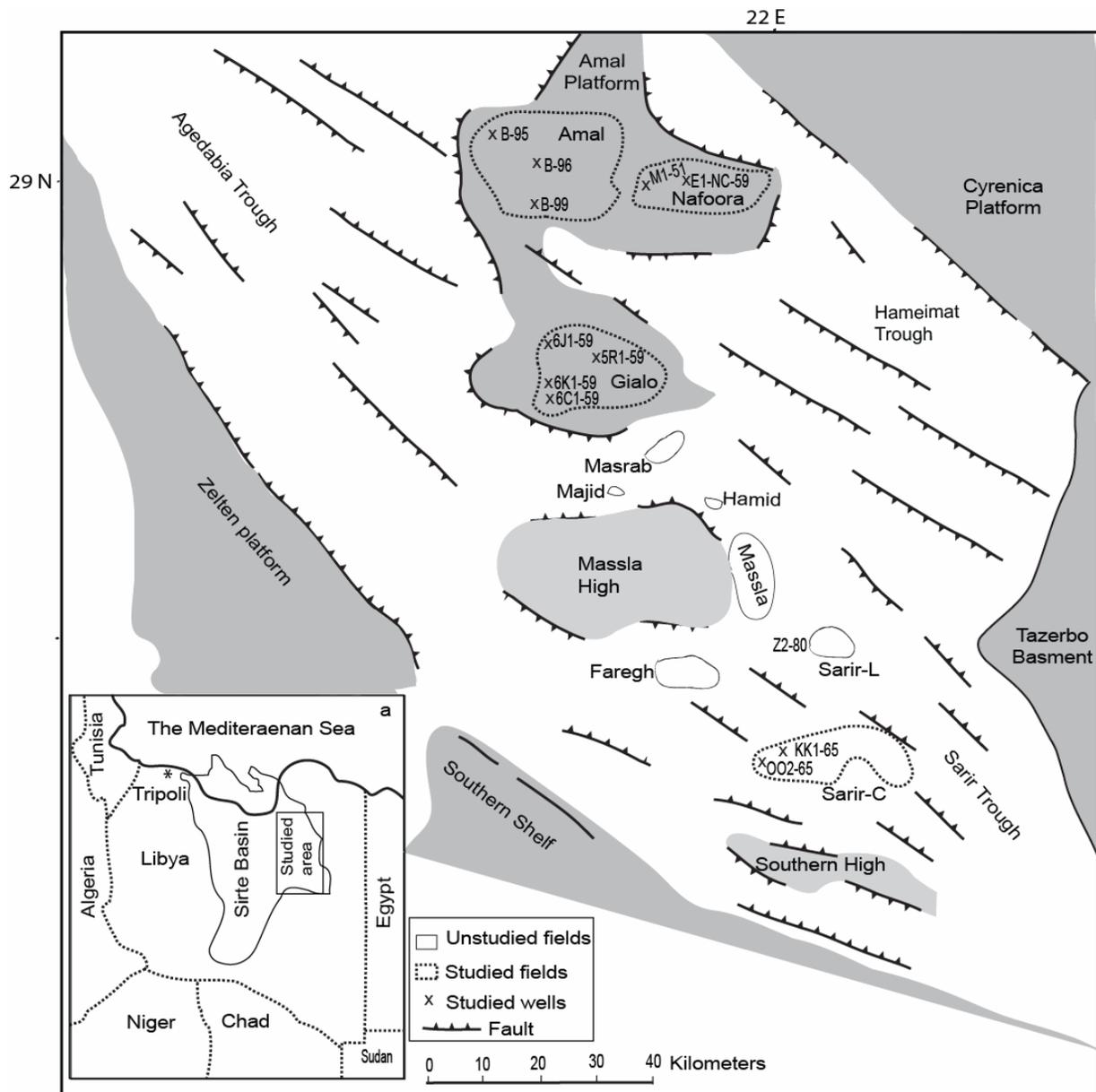


Figure 1. Map shows the location of the Sirte Basin and its structural elements illustrate regional faults, high troughs and well samples in the studied area. Modified from Ahlbrandt (2001) and Aboglila *et al.* (2010) [25].

(**Figure 2**) comprises mostly continental sandstones, although lacustrine shales in the Faregh and Massla fields in the Hameimat Trough (**Figure 1**) may act as source rocks for waxy oils in the southern part of the Agedabia Trough [4-6]. Thermal maturity in Cretaceous formations differs between the basal and uppermost shales. Vitrinite reflectance (R_o) data indicate that the main source rocks of upper Cretaceous have reached three levels of thermal maturity and generated is dominantly oil [5].

Geological Setting

Five basin-fills are present in the Sirte Basin and rest on

Precambrian basement [1,3,8-10]. Pre-rift sediments comprise clastic sediments of Cambrian to Ordovician age (e.g. Amal Formation) (**Figure 2**). The first Mesozoic syn-rift sequence comprises of continental-marine clastics of the Nubian and Sarir sandstones. This cycle was followed by deposition of Upper Cretaceous marine clastics and carbonates. The Upper Cretaceous succession is characterised by extensive lateral and vertical facies changes due to the tectonic instability of the period [10]. The Late Cretaceous Bahi, Lidam, Etel, Maragh, Rachmat, Tagrifet, Rakb, Sirte and Kalash Formations comprise the second basin syn-rift sequence (**Figure 2**) [11]. Deposition within structural troughs was characterised by

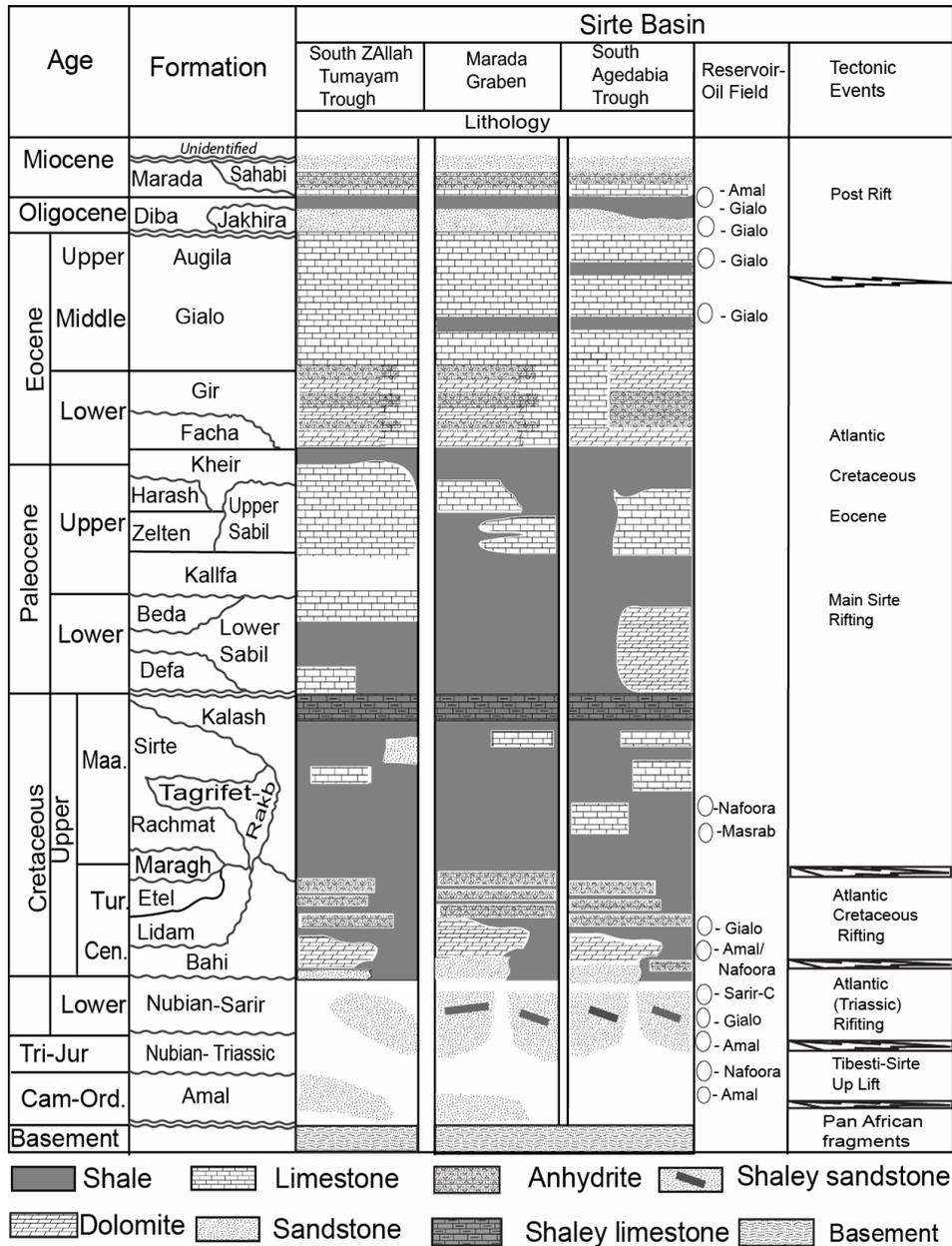


Figure 2. Stratigraphic column of the Sirte Basin highlighting the lithologies of the formations, the reservoir units of the oil fields demonstrates age, formations, lithology, main reservoir-oil fields and its tectonic events. Modified from Barr and Weeger (1972), Burwood *et al.* (2003) and Aboglila *et al.* (2010).

fine-grained siliciclastics whereas the highs were characterised by shallow-marine carbonates [10]. The Bahi Formation (Figure 2) was deposited in a littoral or very shallow marine environment during the Cenomanian. The Lidam Formation represents the first marine unit for the majority of the basin and comprises mainly of dolomite and shale with thin beds of anhydrite in the higher part of formation (Figure 2) [7,12]. The Etel Formation is limited to the central and southern parts of the Sirte Basin but even in those areas it is absent on the highs. The marine Sirte Formation consists of a shale sequence

with thin interbedded limestones and is widely distributed throughout the basin grabens reaching depths of 500 m in the Zallah Trough and 700 m in the Agedabia Trough [7,11]. There was a shallowing of the depositional environment during the Maastrichtian with the shaley limestones of the Kalash Formation deposited under shallow marine conditions [11]. The third syn-rift sequences, corresponding to the main Sirte rifting events of Palaeocene to Eocene Age, were carbonates, with minor evaporates. The onset of rifting corresponded to a deepening in the basin with thick, deep marine sections (e.g.

Khalifa Formation) deposited in troughs and carbonate buildups on the platforms (e.g. Lower Sabil and Defa Formations). These carbonate platforms extended across the western part of the basin indicating an open marine environment. The syn-rift fill sequence was complete in Middle Eocene with deposition of mixed carbonates and siliciclastics followed by continental clastics, which are fairly uniform throughout the basin (**Figure 2**). The Gir Formation limestone and anhydrite form reliable seals for the Facha Formation (dolomite). Post syn-rift deposition of shallow marine carbonates occurs from the Middle Eocene to the Oligocene across the Sirte Basin with the exception of the northwest where there are minor units of shale [11]. The Oligocene regression resulted in different environmental conditions within the basin reflecting the different lithologies of continental sandstone in the south and marine carbonates and shales in the central and eastern parts of the basin (**Figure 2**) [7,11]. During the Miocene the deposition environment in the East Sirte Basin was fluvial along the basin margins, marginal marine towards the north and a marine shelf in the north-east. The Miocene Marada Formation consists of anhydrite, sandstone, and sandy limestone, which are an interfingering of assorted continental, littoral, and distal/marine facies [7,11,13]. The purpose of this paper is to study a total of ninety-nine Cuttings samples from seven Cretaceous formations by Rock-Eval screening, and 21 samples were subjected to more detailed biomarker analyses.

2. Materials and Methods

2.1. Samples

Ninety-three samples of drill cuttings were collected by the National Oil Corporation (NOC) in Tripoli from 11 different wells, located in the Amal, Gialo, Nafuora, and Sarir Fields (**Figure 1**). The units sampled were the Upper Cretaceous Sirte, Rakb, Tagrifet Rachmat and Bahi Formations dominated a shale sequence with thin limestone interbeds and the Lower Cretaceous sample Nubian Formation consists of a diversity of interbedded non-marine lithofacies, shales and conglomerates (**Figure 2**). The terms Nubian Sandstone and Sarir Formation have been used by many authors for all or part of the non-marine Lower Cretaceous units (c.f., [7]).

2.2. Preparation of Cutting Samples

The cutting samples were washed with doubly distilled water and dried at room temperature prior to analysis. Following Rock-Eval pyrolysis and TOC analysis (see below), a suite of representative samples was selected for more detailed organic geochemical examination. These samples were ground to a fine powder (particle size of <150 μm) using a ring-mill (Rocklabs).

2.3. Rock-Eval Pyrolysis and Total Organic Carbon (TOC) Measurements

Rock-Eval pyrolysis of powdered rock (10 - 50 mg) was carried out on a Girdel Rock-Eval instrument, while the TOC was measured on a Leco instrument. Samples with low TOC values (<0.5%) were considered unsuitable for Rock-Eval pyrolysis and therefore not subjected to further analyses.

2.4. Solvent Extraction and Isolation of the Maltenes

Twenty-one cuttings samples from representative formations (Sirte, Tagrifet, Rakb, Rachmat, Bahi and Nubian Formations) were selected for solvent extraction based on TOC values (>0.3%). About 10 - 20 g of ground sediment was extracted in an ultrasonic bath for two hours using a 9:1 mixture of dichloromethane (DCM) and methanol (MeOH). The solvent extract was then filtered and excess solvent removed by carefully heating on a sand bath (60°C) to obtain the bitumen. Asphaltenes were precipitated by mixing the bitumen with an excess of chilled n-heptane. Maltenes were fractionated using a small-scale column chromatographic method [14]. In brief, the sample (maltenes, about 10 - 20 mg) was applied to the top of a small column (5.5 cm \times 0.5 cm *i.e.*) of activated silica gel (120°C, 8 h). The aliphatic hydrocarbon (saturated) fraction was eluted with n-pentane (2 mL); the aromatic hydrocarbon fraction with a mixture of n-pentane and DCM (2 mL, 7:3 v/v); and the polar (NSO) fraction with a mixture of DCM and MeOH (2 mL, 1:1 v/v).

2.5. Gas Chromatography-Mass Spectrometry (GC-MS)

Aliphatic and aromatic fractions were analysed by GC-MS using a Hewlett Packard (HP) 5973 mass-selective detector (MSD) interfaced to a HP6890 gas chromatograph (GC). A HP-5MS (J and W Scientific) GC column (5% phenylmethylsiloxane stationary phase) was used with helium as the carrier gas. The GC oven was programmed from 40°C to 310°C at 3°C/min, after which it was held isothermal for 30 min. Samples were dissolved in n-hexane and introduced by the HP6890 auto-sampler into a split-splitless injector operated in the pulsed-splitless mode. Biomarker data were acquired in a full-scan mode (m/z 50 - 500). The ion source was operated in electron ionization (EI) mode at 70 eV. Selected ion monitoring (SIM) was used to identify the terpanes, steranes and triaromatic steroids by monitoring m/z 191, 217, 218 and 231 ions. Selected aromatic compounds were identified using m/z 178 (phenanthrene), m/z 156 (dimethylnaphthalenes) and m/z 184 (dibenzothiophene) ions and

relative retention time data reported in the literature.

3. Results

3.1. Bulk Geochemical Parameters

TOC (%) and Rock-Eval pyrolysis measurements for the studied samples show quite diverse values (**Table 1**). TOC values from Kalash Formation range 0.21 to 0.28, Sirte Formation range between 0.18% and 5.50%, Tagrifet Formation range between 0.36% and 5.16%, Tagrifet Formation range between 0.36% and 5.16%. Rakb Formation samples have TOC values ranging from 1.00% to 1.42%, Rachmat formation have TOC values ranging from 0.60% to 1.90%, Bahi Formation from has

a TOC of 0.90%, while TOC values obtained from the Nubian Formation range between 0.23% to 0.69. Rock-Eval pyrolysis data measured for the rocks based on parameters of OI, HI, T_{max} , S₂, S₁ and PI demonstrate fairly varied values between formations (**Table 1**). Results of these parameters for studied samples range OI: 3 - 309, HI: 115 - 702, T_{max} : 425 - 440, S₂: 0.27 - 22.80, S₁: 0.16 - 51.80 and PI: 0.07 - 1.55. Plot of hydrogen index (HI) versus oxygen index (OI) (**Figure 3**) illustrating the variation of kerogen type (I, II and III), while plot of S₂ versus TOC (**Figure 4**) illustrating the variation of organic richness and petroleum generation potential in source rocks.

Table 1. Range of rock eval/TOC data for selected formations from the East Sirte Basin

Formation	Samples	TOC	OI	HI	T_{max}	S ₂	S ₁	PI
Sirte	47	0.18 to 5.50	3 - 185	115 - 481	427 - 437	0.27 - 21.40	0.16 - 49.60	0.07 - 1.55
Tagrifet	15	0.36 to 5.16	94 - 210	242 - 612	426 - 440	2.01 - 22.80	0.26 - 51.80	0.11 - 0.79
Rakb	3	1.00 to 1.42	91 - 129	208 - 415	428 - 434	2.08 - 5.90	0.30 - 1.11	0.09 - 0.20
Rachmat	19	0.60 to 1.90	49 - 221	126 - 702	428 - 434	1.18 - 11.46	0.20 - 31.04	0.09 - 0.43
Bahi	1	0.9	309	413	428	2.75	3.92	0.59
Nubian	8	0.23 to 0.69	262 - 280	419 - 433	425 - 426	2.22 - 2.91	3.05 - 3.79	0.54 - 0.58

TOC (wt%): total organic carbon; HI = Hydrogen Index ($S_2 \cdot 100 / \text{TOC}$) and OI = Oxygen Index ($S_3 \cdot 100 / \text{TOC}$); T_{max} (°C): maximum pyrolysis temperature yield; S₂: maximum temperature yield (mg HC/g rock); S₁: low temperature hydrocarbon yield (mg HC/g rock); PI: Production Index ($S_1 / S_1 + S_2$); n.d. not determined.

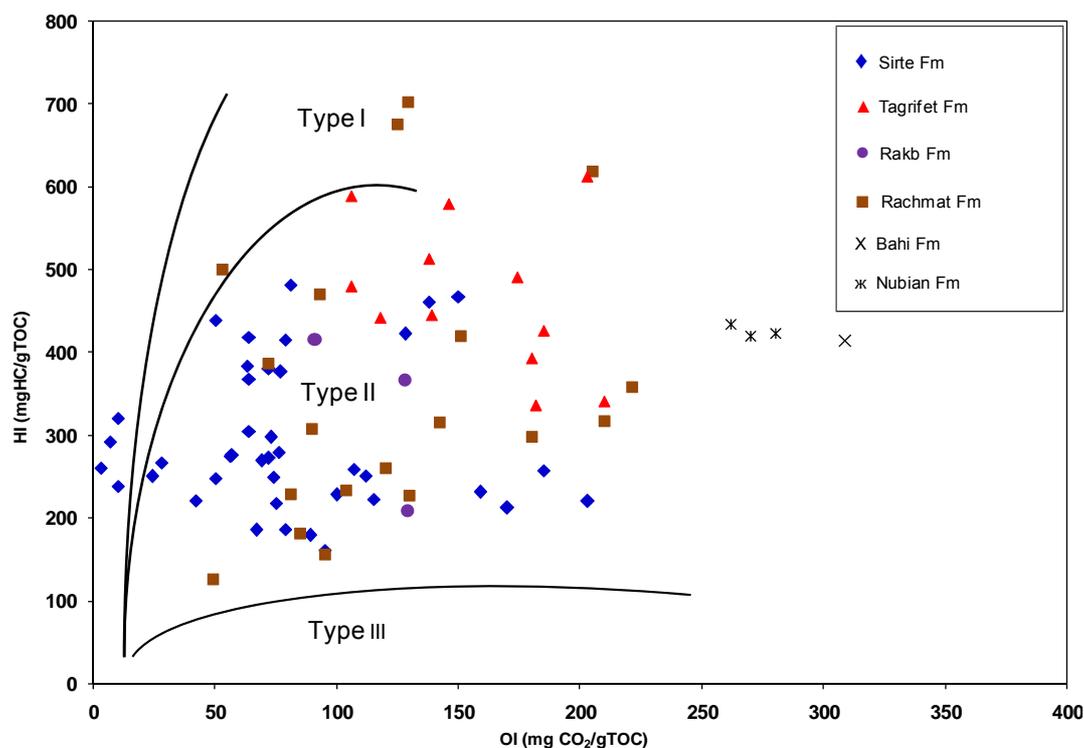


Figure 3. Plot of hydrogen index (HI) versus oxygen index (OI) illustrating the variation of kerogen type (I, II and III) in source rocks of the East Sirte Basin.

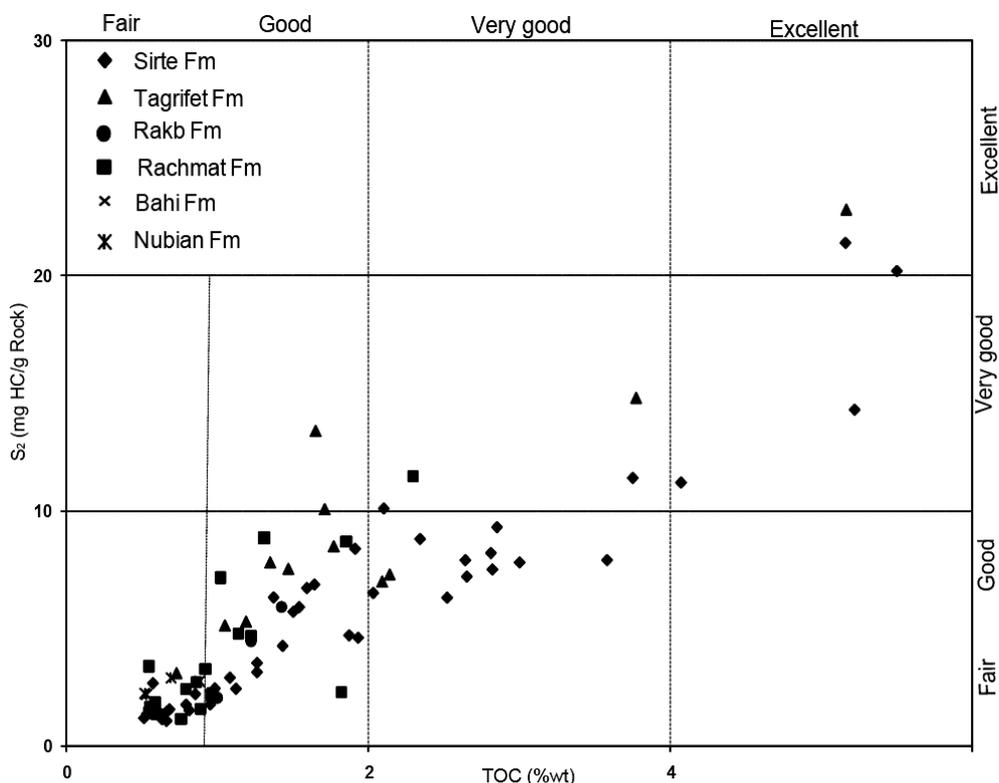


Figure 4. Plot of rock-eval S_2 (mg HC/g rock) versus total organic carbon (TOC, wt%) illustrating the variation of organic richness and petroleum generation potential in source rocks of the East Sirte Basin.

3.2. Vitrinite Reflectance (% Ro)

Vitrinite reflectance is the most extensively used thermal maturity indicator of kerogen (e.g. [15]), and was used to evaluate the studied samples. Vitrinite reflectance data of representative samples from the Sirte Formation range from 0.90 - 1.38, the Tagrifet Formation range from 0.51 - 0.58, the Rakh Formation 0.46 - 0.48, the Rachmat Formation have %Ro ranges between 0.53 - 0.85, the sample of Bahi formation has 0.55 %Ro and Nubian Formations have %Ro values ranging between 0.54 - 0.57 (Table 2 and Figure 5).

3.3. Molecular Composition

Thermal Maturity and Depositional Environment

Two well-established biomarker parameters [16,17] used as geochemical parameters of thermal maturity calculated from the distribution and abundance of aliphatic biomarkers (Table 2). In representative samples ($n = 21$), $T_s/T_s + T_m$ values range from 0.41 to 0.62 and $20S/20S + 20R$ values from 0.22 to 0.58. Geochemical parameters of palaeoenvironments from the distribution and abundance of aliphatic and aromatic isoprenoids for studied formations. The pristane to phytane (Ph/Ph) values range: 0.65 - 1.25 and dibenzothiophene to phenanthrene (DBT/P) ranges: 0.04 - 0.47) values of the source rocks are

shown in Table 3. Data for parameters of lithofacies such $C_{19}TT/C_{23}TT$ ratio and $C_{24}TeT/C_{23}TT$ ratio [18] are established and demonstrated in Table 3. While a difference in the origin of their OM is estimated, basing on partial mass chromatograms of the hopane, tricyclic terpane and sterane distributions of the source rocks are illustrated in Figure 6.

4. Discussion

4.1. Bulk Geochemical Parameters

Rock-Eval pyrolysis and TOC (%) measurements for the studied samples show quite diverse values (Table 1). The organic matter riches of sediments estimated typically using the TOC wt%. Rich of OM in source rocks can be calculated by a worldwide factor of [19]. Reference [19] suggested that, a TOC value of 1.0% is the lower bound for an effectual source rock, as a source rock by less than 1.0% of TOC can never produce sufficient oil to begin primary migration. TOC values < 0.4% indicate low source rock potential. Rock-Eval pyrolysis data for all formations, including S_1 and S_2 (mg HC/g rock), T_{max} ($^{\circ}C$), production indices (PI), hydrogen indices ($HI = \text{mg HC/g TOC}$) and oxygen indices ($OI = \text{mg CO}_2/\text{g TOC}$) were measured. The majority of the source rocks contain Type II kerogen [16], while the higher OI values of the

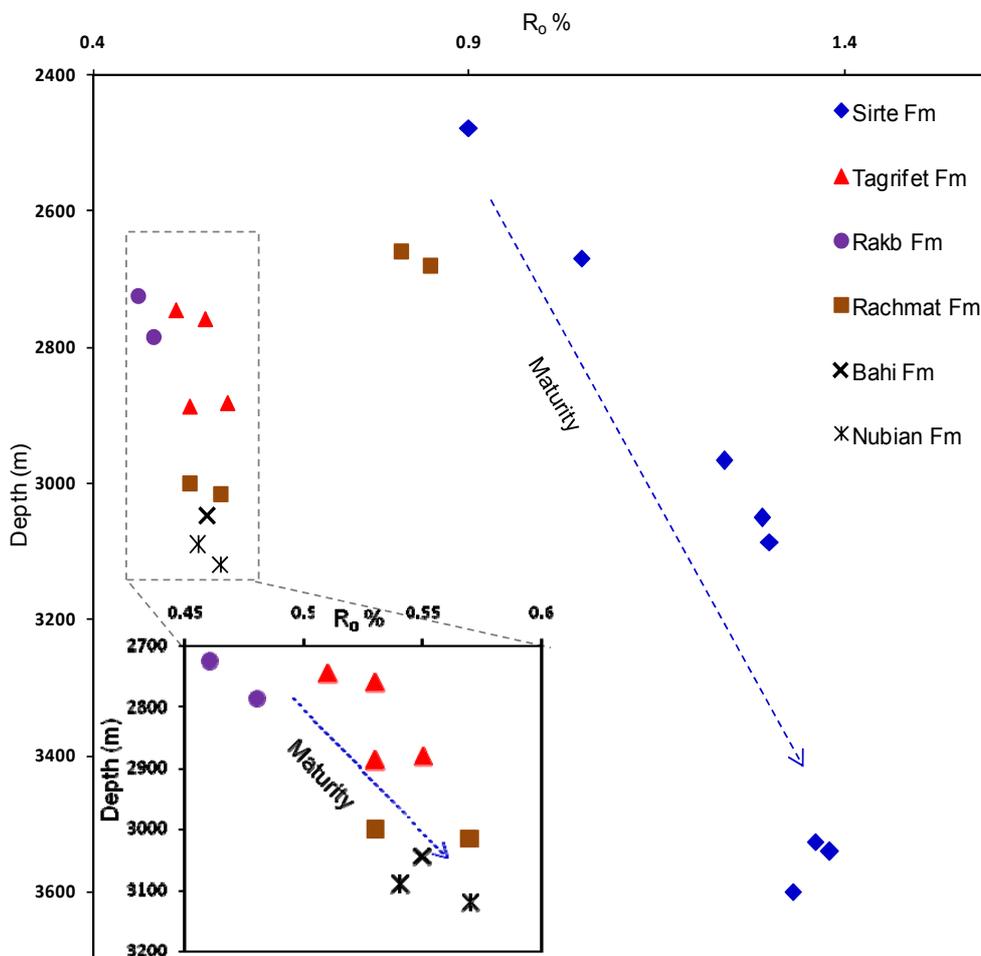


Figure 5. Plot of vitrinite reflectance versus depth for selected source rock extracts from the East Sirte Basin.

Bahi and Nubian Formations indicate mixed Type II-III kerogen. The high values (>1.0) for the S1 peak (free hydrocarbons) and the abnormally high PI values (>0.2) are indicative of migrated bitumen in [7,20] as observed in other studies [21]. Vitrinite reflectance (% R_o) measurements show some correlation with the depths of the samples. Both the Sirte and Rachmat Formation samples reached the oil window whereas Tagrifet, Rakb, Bahi and Nubian Formations supporting an early to mid-stage thermal maturity.

4.2. Molecular Composition

4.2.1. Thermal Maturity Parameters

The different values of Biomarker parameters are spanning the onset of oil generation (immature to mature). The highest maturities are displayed by the Sirte Formation in the Gialo field, in agreement with the findings of [3]. The Sirte Formation likewise appears to be considerably more mature than other formations studied herein based on measurements of methylphenanthrene index (MPI-1) and calculated vitrinite reflectance ($R_c = 0.60$

MPI + 0.4: [22]). The elevated maturity of the Sirte Formation ($R_c = 0.9\% - 1\%$) in agreement vitrinite reflectance data (above) and from the adjacent Agedabia Trough ($R_o \approx 1.2\% - 2\%$: [7]). Although stratigraphically older, the Tagrifet, Rachmat, Rakb, Bahi and Nubian formations within the Hameimat and Sarir Troughs are at the early stages of oil generation ($R_c = 0.65\% - 0.76\%$).

4.2.2. Molecular Composition Indicators of Depositional Environment

Molecular composition indicators of depositional environment revealed the nature of their respective depositional settings (Table 3). The DBT/P values are characteristic of marine shales, whereas in most samples, the Pr/Ph ratio is <1 , indicating deposition under anoxic conditions. The latter are commonly associated with hypersalinity. The slightly higher Pr/Ph values of six studied Formations suggest suboxic depositional conditions. The hopane, tricyclic terpane and sterane distributions of the source rocks (Figure 6) are far from uniform, reflecting differences in the origin of their OM. For example, the relative abundance of C_{27} , C_{28} and C_{29} regular steranes

Table 2. Vitrinite reflectance and geochemical parameters of thermal maturity calculated from the distribution and abundance of aliphatic biomarkers for the source-rocks of the East Sirte Basin.

Field	Well	Formation	Depth (m)	%R _o	Ts/Ts + Tm	aaaC ₂₉ S/S + R
Gialo	6C1-59	Sirte	3053	1.29	0.61	0.49
Gialo	6C1-59	Sirte	3603	1.33	0.62	0.58
Gialo	6C1-59	Sirte	3088	1.30	0.61	0.50
Gialo	6J1-59	Sirte	3529	1.36	0.62	0.50
Gialo	6J1-59	Sirte	3542	1.38	0.62	0.50
Gialo	6R1-59	Sirte	2967	1.24	0.58	0.46
Sarir-C	KK1-65	Sirte	2670	1.05	0.61	0.40
Sarir-C	OO2-65	Sirte	2479	0.90	0.50	0.36
Nafoora	M1-51	Tagrifet	2882	0.58	0.45	0.24
Sarir-C	KK1-65	Tagrifet	2745	0.51	0.54	0.35
Sarir-C	KK1-65	Tagrifet	2760	0.55	0.53	0.36
Sarir-C	OO2-65	Tagrifet	2612	0.53	0.46	0.22
Amal	B-96	Rakb	2786	0.48	0.41	0.24
Amal	B-95	Rakb	2725	0.46	0.39	0.17
Nafoora	M1-51	Rachmat	3015	0.57	0.47	0.24
Nafoora	M1-51	Rachmat	3000	0.53	0.50	0.35
Sarir-C	OO2-65	Rachmat	2681	0.85	0.58	0.36
Sarir-C	OO2-65	Rachmat	2660	0.81	0.53	0.42
Nafoora	M1-51	Bahi	3045	0.55	0.47	0.35
Nafoora	M1-51	Nubian	3120	0.57	0.47	0.33
Nafoora	M1-51	Nubian	3091	0.54	0.48	0.34

R_o = Vitrinitereflectance; Ts/Ts + Tm = 18 α (H)-22,29,30-trisnorhopane/18 α (H)-22,29,30-trisnorhopane + 17 α (H)-22,29,30-trisnorhopane; S/S + R = C₂₉aaa20S/C₂₉aaa20S + C₂₉aaa20R.

vary depending on the contributions of marine or lacustrine phytoplankton, green algae and/or land plants to their kerogen [23,24]. The sterane distributions of most of the samples are dominated by the C₂₇ homologue, usually attributed to a marine algal source. The sample from the Tagrifet Formation in the Nafoora field is an exception, where the C₂₈sterane is co-dominant with the C₂₇ and C₂₉ steranes (**Figure 6**). However, the Tagrifet Formation contains fossil planktonic foraminifera, bryozoans and dinoceramid, andrudist molluscs, clearly supporting a marine environment. A high C₁₉TT/C₂₃TT ratio and low relative abundance of C₂₄TeT/C₂₃TT are features commonly associated with marine shale and carbonate lithofacies [18]. Thus, the low C₁₉TT/(C₁₉TT + C₂₃TT) and C₂₄TeT/(C₂₄TT + C₂₃TT) in all rock samples studied (**Table 3**)

are consistent with their interpreted marine affinity.

5. Conclusion

A variety of organic geochemical analyses were applied to set of rock extracts from the East Sirte Basin (Libya). Results of this study support the understanding that the Sirte Shale formation (Campanian/Turonian) is the main source rock in this petroleum region with an indication of the geochemical evaluation of other formations in agreement with other available studies. Based on Ts/Ts + Tm and aaaC₂₉20S/20S + 20R the thermal maturities of the source rocks from the Sirte Formation were found to be higher than the Tagrifet, Rakb, Rachmat, Bahi, and Nubian formations. Ph/Ph, DBT/P, triterpanes andsteranes

Table 3. Geochemical parameters of palaeoenvironments from the distribution and abundance of aliphatic and aromatic isoprenoids for studied formations.

Field	Well	Formation	Depth (m)	Pr/Ph	DBT/P	C ₁₉ TT/C ₂₃ TT	C ₂₄ TeT/C ₂₃ TT
Gialo	6C1-59	Sirte	3053	0.78	0.46	0.17	0.26
Gialo	6C1-59	Sirte	3603	0.86	0.47	0.15	0.26
Gialo	6C1-59	Sirte	3088	1.10	0.22	n.d.	n.d.
Gialo	6J1-59	Sirte	3529	0.68	0.36	0.08	0.35
Gialo	6J1-59	Sirte	3542	0.92	0.29	0.11	0.38
Gialo	6R1-59	Sirte	2967	0.92	0.27	n.d.	n.d.
Sarir-C	KK1-65	Sirte	2670	0.86	0.31	n.d.	n.d.
Sarir-C	OO2-65	Sirte	2479	0.77	0.13	0.10	0.28
Nafoora	M1-51	Tagrifet	2882	0.86	0.16	0.19	0.26
Sarir-C	KK1-65	Tagrifet	2745	1.13	0.19	0.1	0.31
Sarir-C	KK1-65	Tagrifet	2760	1.25	0.11	0.09	0.31
Sarir-C	OO2-65	Tagrifet	2612	0.85	0.13	0.11	0.35
Amal	B-96	Rakb	2786	1.25	0.25	0.11	0.29
Amal	B-95	Rakb	2725	1.01	0.30	n.d.	n.d.
Nafoora	M1-51	Rachmat	3015	0.70	0.13	0.17	0.29
Nafoora	M1-51	Rachmat	3000	1.12	0.11	n.d.	n.d.
Sarir-C	OO2-65	Rachmat	2681	0.80	0.21	0.1	0.29
Sarir-C	OO2-65	Rachmat	2660	0.68	0.30	n.d.	n.d.
Nafoora	M1-51	Bahi	3045	0.68	0.04	0.09	0.3
Nafoora	M1-51	Nubian	3120	0.68	0.28	n.d.	n.d.
Nafoora	M1-51	Nubian	3091	0.65	0.31	0.1	0.31

Pr = pristane/Ph = phytane; DBT = dibenzothiophene/P = phenanthrene; C₁₉TT/C₂₃TT = C₁₉ tricyclic terpane/C₁₉ tricyclic terpane + C₂₃ tricyclic terpane; C₂₄TeT/C₂₃TT = C₂₄ tetracyclic terpane/C₂₄ tricyclic terpane + C₂₃ tricyclic terpane.

tion (NOC) in Tripoli and staff of the Libyan Petroleum companies (Waha, Veba and Gulf) for providing samples.

REFERENCES

- [1] K. Ghorri and R. Mohammed, "The Application of Petroleum Generation Modelling to the Eastern Sirt Basin, Libya," *Geology of the Sirt Basin: Amsterdam, Elsevier*, Vol. 2, 1996, pp. 529-540.
- [2] G. Barić, D. Španić and M. Maričić, "Geochemical Characterisation of Source Rocks in NC-157 Block (Zalan Platform), Sirt Basin," 1996.
- [3] M. El-Alami, S. Rahouma and A. Butt, "Hydrocarbon Habitat in the Sirte Basin, Northern Libya," *Petroleum Research Journal*, Vol. 1, 1989, pp. 19-30.
- [4] A. El-Hawat, A. Missallati, A. Bezan, *et al.*, "The Nubian Sandstone in Sirt Basin and Its Correlatives," *Geology of the Sirt Basin: Amsterdam, Elsevier*, Vol. 2, 1996, pp. 3-30.
- [5] R. Burwood, J. Redfern and M. Cope, "Geochemical Evaluation of East Sirte Basin (Libya) Petroleum Systems and Oil Provenance," *Geological Society, London, Special Publications*, Vol. 207, No. 1, 2003, pp. 203-240.
- [6] S. Aboglila, K. Grice, K. Trinajstić, *et al.*, "The Significance of 24-Norcholestanes, 4-Methylsteranes and Dinosteranes in Oils and Source-Rocks from East Sirte Basin (Libya)," *Applied Geochemistry*, Vol. 26, No. 9-10, 2011, pp. 1694-1705.
[doi:10.1016/j.apgeochem.2011.04.026](https://doi.org/10.1016/j.apgeochem.2011.04.026)
- [7] D. Hallett, "Petroleum Geology of Libya," Elsevier Science Limited, Kidlington, 2002.
- [8] R. Gras, "Structural Style of the Southern Margin of the

- Messlah High,” *Geology of the Sirte Basin: Amsterdam, Elsevier*, Vol. 3, 1996, pp. 201-210.
- [9] D. S. Macgregor, “The Hydrocarbon Systems of North Africa,” *Marine and Petroleum Geology*, Vol. 13, No. 3, 1996, pp. 329-340. [doi:10.1016/0264-8172\(95\)00068-2](https://doi.org/10.1016/0264-8172(95)00068-2)
- [10] A. Abadi, “Tectonics of the Sirte Basin,” PhD Dissertation, Vrije Universiteit, Amsterdam, ITC, Enschede, 2002, p. 187.
- [11] F. Barr and A. Weegar, “Stratigraphic Nomenclature of the Sirte Basin,” The Petroleum Exploration Society of Libya, Libya, 1972.
- [12] D. C. Rusk, “Libya: Petroleum Potential of the Underexplored Bas Centers—A Twenty-First-Century Challenge,” In: M. W. Downey, J. C. Threet and W. A. Morgan, Eds., *Petroleum Provinces of the Twenty-First Century: AAPG Memoir*, The American Association of Petroleum, 2001, pp. 429-452.
- [13] T. S. Ahlbrandt, “The Sirte Basin Province of Libya: Sirte-Zelten Total Petroleum System: US Department of the Interior,” US Geological Survey, 2001.
- [14] T. P. Bastow, B. G. van Aarssen and D. Lang, “Rapid Small-Scale Separation of Saturate, Aromatic and Polar Components in Petroleum,” *Organic Geochemistry*, Vol. 38, No. 8, 2007, pp. 1235-1250. [doi:10.1016/j.orggeochem.2007.03.004](https://doi.org/10.1016/j.orggeochem.2007.03.004)
- [15] B. Tissot and D. H. Welte, “Petroleum Formation and Occurrence,” Springer-Verlag, Berlin and New York, 1984.
- [16] K. Peters and J. Moldowan, “The Biomarker Guide,” Prentice-Hall, Inc., Upper Saddle River, 1993.
- [17] K. Peters, C. Walters and J. Moldowan, “The Biomarker Guide, Vol. 1 and 2,” Cambridge University Press, Cambridge, 2005.
- [18] F. R. Aquino Neto, J. M. Trendel, A. Restle, J. Connan and P. Albrecht, “Occurrence and Formation of Tricyclic and Tetracyclic Terpanes in Sediments and Petroleum,” In: M. Bjorøy, Ed., *Advances in Organic Geochemistry* 1981, John Wiley & Sons Ltd., Chichester, 1983, pp. 659-667.
- [19] C. Barker, “Thermal Modeling of Petroleum Generation: Theory and Applications,” Elsevier, Amsterdam, 1996.
- [20] D. Baird, R. Aburawi and N. Bailey, “Geohistory and Petroleum in the Central Sirt Basin,” *Geology of the Sirt Basin: Amsterdam, Elsevier*, Vol. 3, 1996, pp. 3-56.
- [21] F. Shaaban, R. Lutz, R. Littke, *et al.*, “Surce Rock Evaluation and Basin Modelling in NE Egypt (NE Nile Delta and Northern Sinai),” *Journal of Petroleum Geology*, Vol. 29, No. 2, 2006, pp. 103-124. [doi:10.1111/j.1747-5457.2006.00103.x](https://doi.org/10.1111/j.1747-5457.2006.00103.x)
- [22] M. Radke and D. Welte, “The Methylphenanthrene Index (MPI): A Maturity Parameter Based on Aromatic Hydrocarbons,” *Advances in Organic Geochemistry*, Vol. 1983, 1981, pp. 504-512.
- [23] W.-Y. Huang and W. Meinschein, “Sterols as Ecological Indicators,” *Geochimica et Cosmochimica Acta*, Vol. 43, No. 5, 1979, pp. 739-745. [doi:10.1016/0016-7037\(79\)90257-6](https://doi.org/10.1016/0016-7037(79)90257-6)
- [24] J. Volkman, “Sterols in Microorganisms,” *Applied Microbiology and Biotechnology*, Vol. 60, No. 5, 2003, pp. 495-506.
- [25] S. Aboglila, K. Grice, K. Trinajstic, *et al.*, “Use of Biomarker Distributions and Compound Specific Isotopes of Carbon and Hydrogen to Delineate Hydrocarbon Characteristics in the East Sirte Basin (Libya),” *Organic Geochemistry*, Vol. 41, 2010, pp. 1249-1258. <http://www.sciencedirect.com/science/article/pii/S0146638010001294>