

Integrated Geochemical Evaluation of the Hagfah Shale: Depositional Environment, Kerogen Type, and Hydrocarbon Potential in the Sirte Basin, NE, Libya

Fares Fares

University of Benghazi

Mohammed Afkareen

University of Benghazi

Osama Fallah

University of Benghazi

Abobkar Algomati

`abobakar.algomati@bsu.edu.ly`

University of Benghazi

Faraj Faraj

University of Benghazi

Research Article

Keywords: Hagfah Shale, Rock–Eval pyrolysis, hierarchical cluster analysis, source rock evaluation, Sirte Basin

Posted Date: September 30th, 2026

DOI: <https://doi.org/10.21203/rs.3.rs-10309405/v1>

License: © ⓘ This work is licensed under a Creative Commons Attribution 4.0 International License.

[Read Full License](#)

Additional Declarations: No competing interests reported.

1 **Integrated Geochemical Evaluation of the Hagfah Shale: Depositional Environment, Kerogen**
2 **Type, and Hydrocarbon Potential in the Sirte Basin, NE, Libya**

3 Fares F. Fares ¹, Mohammed Afkareen ², Osama A. El Fallah¹, Abobkar E. Algomati ³, Faraj S. Faraj ¹

4 ¹Department of Earth Sciences, Faculty of Science, Benghazi University, Libya

5 ²Exploration Sector, Sirte Oil Company (SOC), Marsa El- Brega, Libya

6 ³Department of Engineering Geology, Faculty of Science, Engineering, University of Bright Star, El-
7 Brega, Libya

8 Corresponding author email: abobakar.algomati@bsu.edu.ly

9 **Abstract**

10 One of the primary Upper Cretaceous shale formations in Libya's Sirte Basin is the Hagfah Shale. The
11 formation was once considered a potential source rock for petroleum. However, the formation's
12 properties as a source rock, including kerogen, thermal maturity, and hydrocarbon retention, have not
13 been well evaluated, and its petroleum potential needs to be assessed. This research aims to investigate
14 the kerogen type, thermal maturity, and hydrocarbon retention of the Hagfah Shale to determine its
15 source-rock potential. Rock-Eval pyrolysis and total organic carbon (TOC) data from six wells
16 representing the Dahra Hofra Platform (Well F12-20), Meanzel Ridge (Well P1-6), Jahama Platform
17 (Well EEE1-6), Zaltan Platform (Well D1-94), Hateiba Ridge (Well OO1-6), and Ajdabiya Trough (Well
18 K1-12) were analyzed. Cluster analysis and standard geochemical cross-plots (TOC % vs. S₁ + S₂, TOC
19 % vs. HI, HI vs. OI, and OSI) were used to evaluate organic richness, kerogen type, thermal maturity,
20 depositional environment, and hydrocarbon retention. The Hagfah Shale exhibits generally low TOC
21 values, indicating poor source rock quality in the Dahra Hofra, Meanzel Ridge, Zaltan, and Jahama
22 Platform wells, while the Hateiba Ridge and Ajdabiya Trough display slightly higher TOC values
23 corresponding to poor-to-fair organic richness. Hydrogen Index data indicate that the organic matter is
24 dominated by Type III kerogen, with minor Type II/III in the Jahama Platform and Ajdabiya Trough and
25 minor Type IV in the Zaltan Platform, suggesting predominantly gas-prone source rocks with limited oil-
26 generating potential. Cluster analysis identified two to three geochemical groups within each well,
27 reflecting variations in kerogen type, organic richness, and thermal maturity. TOC% vs. (S₁ + S₂) and
28 TOC% vs. HI relationships place most samples within the poor hydrocarbon-generation-potential field.
29 Oil Saturation Index values exceeding 100 mg HC/g TOC in parts of the Jahama Platform and Hateiba
30 Ridge indicate localized hydrocarbon enrichment and improved retention potential, whereas the
31 remaining wells show limited hydrocarbon potential. These results indicate that the depositional
32 environment controls organic matter preservation, but the generally low TOC% and the predominance
33 of Type III kerogen limit the overall source-rock potential of the Hagfah Shale. Finally, the Hagfah Shale
34 has limited petroleum source-rock potential across most structural domains of the Sirte Basin, with only
35 localized intervals showing limited hydrocarbon-retention potential.

Keywords: Hagfah Shale; Rock–Eval pyrolysis; hierarchical cluster analysis; source rock evaluation; Sirte Basin.

1.Introduction

The Sirte Basin is one of North Africa's most prolific petroleum basins and Libya's primary hydrocarbon-producing province (Barr and Weegar 1972; Gras and Thusu 1998). It is located in north-central Libya and covers a large area characterized by a series of structural depressions (troughs) and elevated platforms caused by Mesozoic to Cenozoic rifting and subsidence. This tectonic framework has played a critical role in regulating sedimentation patterns, stratigraphic evolution, and hydrocarbon accumulation (Guiraud and Bosworth 1997). The basin has a thick sedimentary sequence ranging from the Paleozoic to the Cenozoic eras, with large hydrocarbon systems primarily associated with Late Cretaceous and Paleogene source rocks (Gras and Thusu 1998). The principal source rocks are organic-rich Shales deposited in diverse marine and terrestrial settings, with depositional environment, organic matter type, and thermal maturity affecting their quality (Tissot and Welte 1984; Peters and Cassa 1994).

Hydrocarbons produced in the Sirte Basin are typically low in sulfur, with values ranging from 0.15% to 0.66%, and are coupled with small amounts of gas. Oil in the Sirte Basin has API gravities ranging from 32° to 44° (Hallett 2016; Albriki et al. 2021). Hydrocarbons accumulate at depths ranging from 2,300 to 13,100 feet, with reservoir temperatures ranging from 52°C to 143°C. The Hagfah Shale is considered a secondary source rock unit widely distributed across several structural settings within the Sirte Basin, following the main source rocks, such as the Etel Formation (Turonian), Rachmat Formation (Coniacian), Tagrifat Shale (Santonian), and Sirte Shale (Campanian). The quality and hydrocarbon potential of these source rocks vary significantly depending on total organic carbon (TOC) content, kerogen type, thermal maturity, and depositional conditions (Rossi et al. 1991; Hassan and Kendall 2014; Albriki et al. 2021).

Several regional studies have been conducted on the petroleum systems of the Sirte Basin, including evaluations of major source rock units such as the Sirte shale, Rachmat Formation, Tagrifat shale, and Etel Formation, but there is a noticeable lack of focused studies that specifically address the geochemical and depositional characteristics of the Hagfah shale. This represents a considerable information gap, particularly regarding how the Hagfah Shale behaves across various structural settings within the Sirte Basin and its potential contributions to conventional and unconventional petroleum systems. As a result, extensive geochemical characterization of this unit is required to improve our understanding of its role within the basin's petroleum system.

Previous studies, such as those by Aboglila and Elkhalti (2013), indicate that the Upper Cretaceous Sirte, Tagrifet, Rakb, Rachmat, and Bahi formations are effective source rocks with variable organic richness and mixed Type II/III kerogen, indicating both oil- and gas-generating potential. Thermal maturity ranges from early to post-mature stages, with the best hydrocarbon potential observed in intervals that combine higher TOC % with favorable maturity conditions. Overall, these formations contribute significantly to

the petroleum system, with some units showing better potential for hydrocarbon generation and retention than others.

Diasty et al. (2016) analyzed the Cretaceous source rocks of the Etel, Rachmat, Sirte, and Kalash formations in the western Sirte Basin and concluded that their thermal maturity levels vary significantly, as indicated by vitrinite reflectance (V_{Ro}) data. The shales of the Etel and Rachmat formations were found to have reached mature to late-mature stages, while the Sirte Formation exhibits moderate maturity. In contrast, the Kalash Formation source rocks are characterized by early- to mid-maturity stages.

Albriki et al. (2021) concluded that the Upper Cretaceous–Paleogene source rock intervals within the Sirte Basin exhibit variable but generally good hydrocarbon generation potential. The study highlighted that organic richness, kerogen type, and thermal maturity are the main controlling factors governing source rock effectiveness across different structural settings. The results indicate that most source rocks are dominated by mixed Type II/III kerogen, reflecting both marine and terrestrial organic input, with maturity levels ranging from immature to overmature depending on burial depth. The study further emphasized that structural variation within the basin strongly influences hydrocarbon generation, expulsion, and accumulation processes, leading to heterogeneous petroleum potential across the basin.

Shaltami et al. (2021) conducted an organic geochemical evaluation of the Tagrifat Shale in Well A1-NC129, in the Sirte Basin, indicating that the formation contains variable but generally good source-rock potential. The shale is characterized by appreciable organic richness and mixed Type II/III kerogen, reflecting both marine and terrestrial organic input. Thermal maturity data suggest that the Tagrifat Shale has reached the oil window, confirming its capability for hydrocarbon generation. The results further indicate that the Tagrifat Shale exhibits more favorable geochemical characteristics than relatively coeval formations, with greater potential for hydrocarbon generation and retention. Overall, the study confirms that the Tagrifat Shale is a significant contributor to the petroleum system of the Sirte Basin and may also be an unconventional hydrocarbon resource under suitable maturity conditions.

Hallash et al. (2024) conducted a geochemical evaluation of the Upper Cretaceous Rachmat, Tagrifet, and Sirte formations in the Hameimat Trough within the Sirte Basin, indicating fair to excellent source-rock quality, with TOC values ranging from 0.53% to 3.35% and mixed Type II/III kerogen. Thermal maturity data confirm that these formations have reached the oil window stage. However, Oil Saturation Index (OSI) results show that the Sirte and Rachmat formations have low oil saturation and higher exploration risk, whereas the Tagrifet Formation exhibits higher OSI values (>140 mg HC/g TOC), indicating better hydrocarbon retention and greater potential for shale oil development. Overall, the Tagrifet Formation represents the most promising unconventional resource within the study area.

Despite the advances in understanding the petroleum systems of the Sirte Basin, the geochemical characteristics and petroleum potential of the Hagfah Shale across different structural settings remain poorly constrained. Therefore, this study aims to provide an integrated geochemical assessment of the Hagfah Shale by evaluating its organic richness, kerogen type, thermal maturity, depositional

environment, and hydrocarbon retention potential. Rock–Eval pyrolysis and total organic carbon (TOC) data from six wells distributed across different structural provinces of the Sirte Basin are integrated with hierarchical cluster analysis and standard geochemical cross-plots. The study further evaluates the spatial variability of source-rock characteristics and identifies structural settings and intervals with relatively enhanced hydrocarbon potential (Fig. 1).

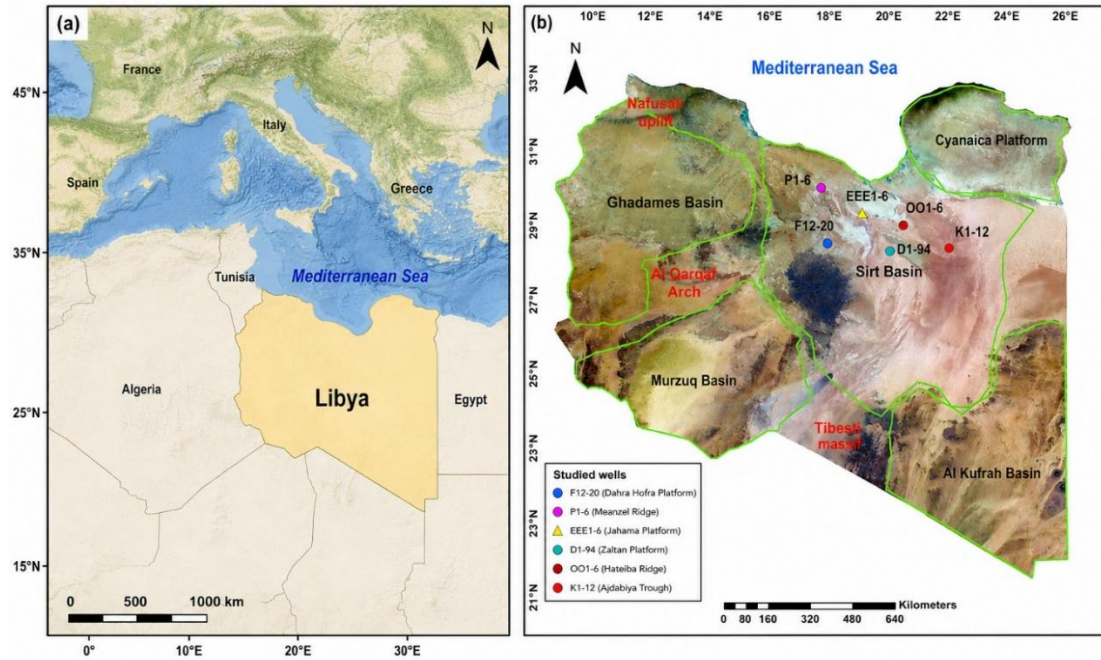


Fig. 1. (a) Location of Libya within the Mediterranean region. (b) Geological map of Libya showing the major sedimentary basins and structural elements, with the location of the Sirte Basin and the six studied wells.

2. Geological setting

2.1. Tectonic and stratigraphic setting

Libya contains five major onshore sedimentary basins: the Cyrenaica, Sirte, Kufra, Murzuq, and Ghadamis basins (Fig. 2A). Among these, the Sirte Basin is the most prolific hydrocarbon-producing basin in the country. The basin is predominantly Mesozoic, Paleogene, and Neogene in age and covers an area of approximately 600,000 km². Its sedimentary succession exceeds 23,000 ft in thickness, reflecting a complex tectono-stratigraphic history associated with prolonged subsidence and rifting. The Sirte Basin consists of a complex system of horsts and grabens that began to develop during the Late Jurassic (Jawazi and Futyan 1996).

The Sirte Basin is divided into several major structural elements, including platforms such as Dahra, Zaltan, and Beda; troughs and grabens such as Ajdabiya, Zallah, Hagfah, Hameimat, Hun, and Kotla; and ridges and structural highs such as Hateiba, Meanzel, Waddan, and Rakb. Each structural province reflects a distinct tectonic and depositional history developed during the rifting and subsidence of the

basin. These structural variations have an important influence on the distribution, thickness, burial depth, thermal maturity, and geochemical properties of source rocks and consequently affect hydrocarbon generation and accumulation processes (Guiraud and Bosworth 1997). Figure 2C shows a west–east structural cross-section through the Sirte Basin, illustrating the major structural components (Roohi 1996).

The basin evolved as a rifted margin along an embayment on the northern African Plate as a consequence of tectonic events associated with the breakup of Pangea. These processes initiated rifting along the present-day northwestern margin of Africa during the Middle Triassic. Subsequent crustal separation and seafloor spreading during the Early Jurassic resulted in the formation of the central Atlantic Ocean between northwest Africa and North America, followed by the opening of the central Tethyan Basin during the Middle Jurassic (Gumati and Schamel 1988; Gumati et al. 1996; Sikander and Basu 2006). Early Cretaceous rifting within the Sirte Basin developed in response to extensional tectonic forces acting along zones of crustal weakness between African crustal blocks. This tectonic activity resulted in the collapse of the pre-existing Sirte Arch, a major NE–SW-oriented positive structural feature. The early rifting phase was accompanied by rhyolitic and basaltic volcanic activity, with granitic intrusions dated to approximately 150 Ma and basic to intermediate volcanic rocks dated to about 130 Ma (Hallett 2002; Abadi et al. 2008; Abdalla et al. 2023a).

During the Late Cretaceous, the basin experienced active subsidence that gradually decreased through time. The Paleocene and early Eocene were characterized by slower subsidence and reactivation of extensional faults associated with the relative movements of the African, American, and Eurasian plates during the opening of the Atlantic Ocean and the evolution of the Tethys Basin along the northern margin of the African Plate (Anketell 1996; Guiraud and Bosworth 1997; Ziegler and Roure 1999; Sikander and Basu 2000).

Organic-rich source rocks in the Sirte Basin were primarily deposited in rapidly subsiding, fault-bounded troughs during the Triassic, Cretaceous, and early Paleocene. Among these, the Campanian source rocks are the most widespread and are responsible for generating most of the basin’s discovered hydrocarbons (Ghori and Mohammed 1996; Ahlbrandt 2001; Abdalla et al. 2023b). Hydrocarbon migration occurred both vertically and laterally through rift-related faults and fractures before accumulation within structural and combined traps on platform highs (Gumati and Nairn 1991; Hallett 2016).

The tectono-stratigraphic evolution of the Sirte Basin can be divided into three main phases: pre-rift, syn-rift, and post-rift. The pre-rift phase was characterized by initial crustal stretching and deposition of thick sandstone successions, including the Amal, Bahi, and Nubian formations, which later became important reservoir rocks in several oil fields (Gumati and Schamel 1988; Hallett 2002). The syn-rift phase was characterized by intense tectonic activity, marine transgression, and rapid subsidence, resulting in the deposition of thick carbonate and organic-rich shale sequences, such as the Rachmat Formation (Ahlbrandt 2001; Sikander and Basu 2006). The post-rift phase was dominated by Paleocene to Miocene

carbonate and shale deposition under varying marine environments, accompanied by continued subsidence and fault reactivation (Anketell 1996; Guiraud and Bosworth 1997) (Fig. 3).

The Hagfah Shale, which is the focus of this study, is composed predominantly of dark-grey to grey calcareous shale enriched with planktonic foraminifera (Fig. 5). It is characterized by fissile shale with variable carbonate content and locally organic-rich intervals, reflecting variations in depositional environment, sedimentation rate, and organic-matter preservation.

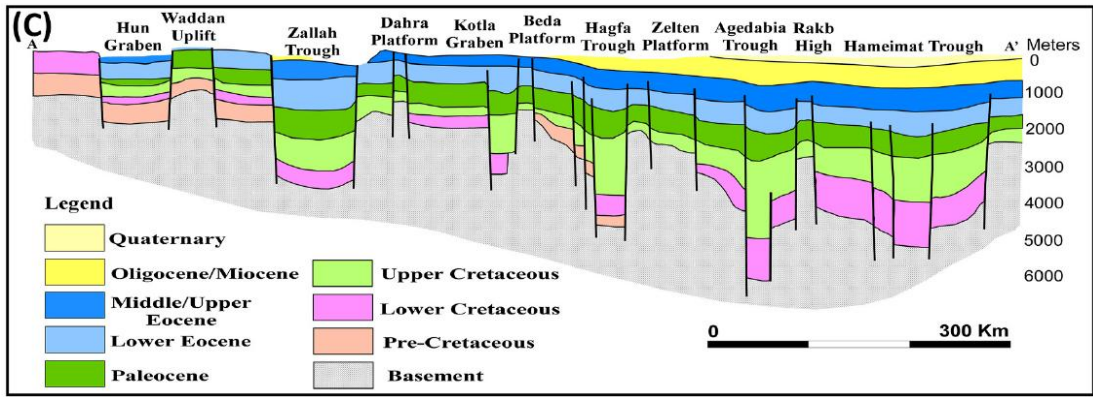
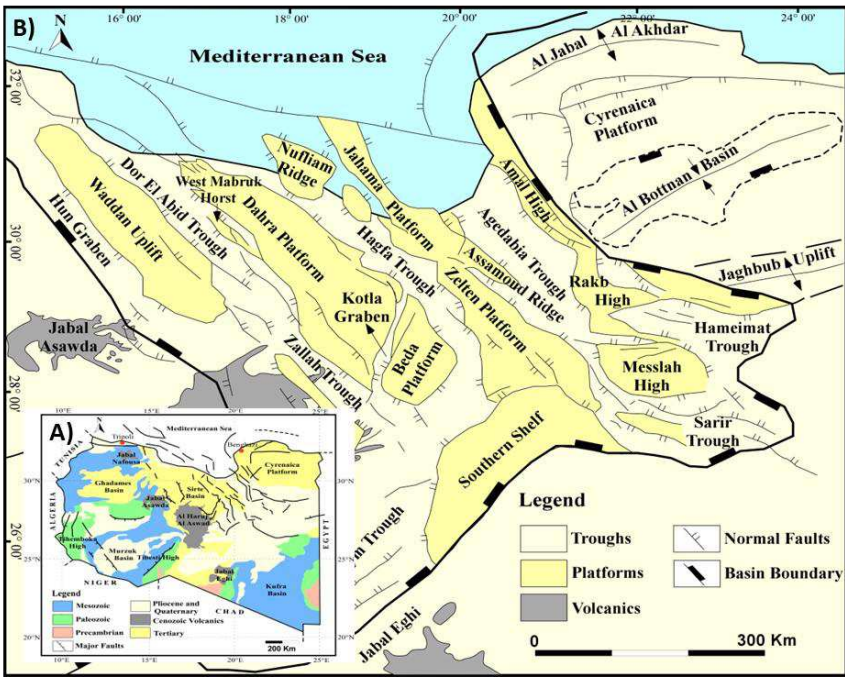


Fig. 2. A) Revealing the main sedimentary basins and faults in Libya (modified after Conant and Goudarzi 1967; Mohammed et al. 2022; Abdalla et al. 2023a, b, 2025). B) Tectonic framework of the Sirte Basin (Abdalla et al. 2025). C) West-east structural cross-section through the Sirte Basin depicting the major structural components (Roohi 1996).

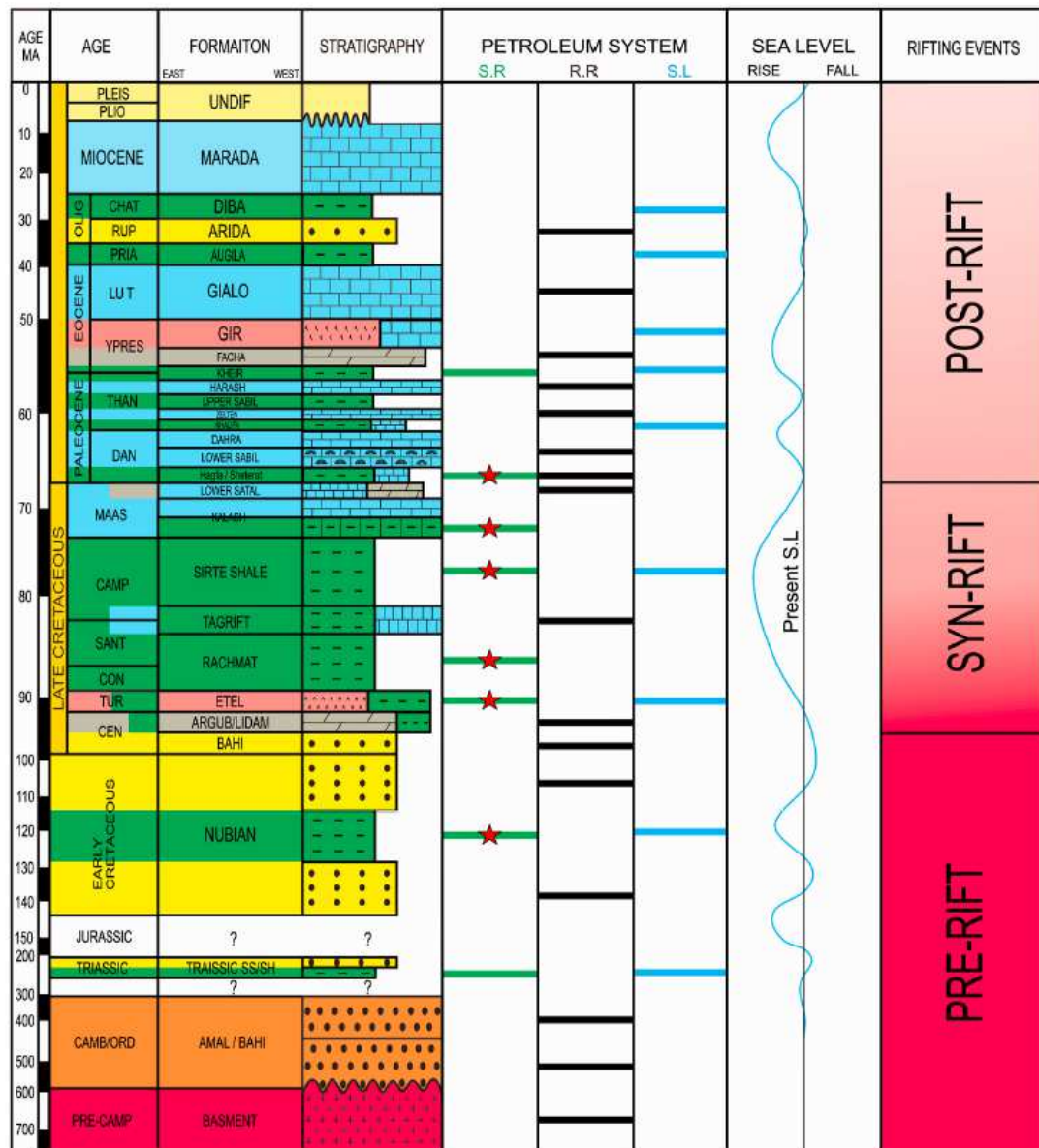


Fig. 3: Generalized stratigraphic column of the Sirte Basin showing the main stratigraphic units, including the studied source-rock intervals (indicated by red stars). The figure also illustrates the key elements of petroleum systems, where S.R., R.R., and S.L. represent the source rock, reservoir rock, and seal rock, respectively. The figure highlights major sea-level fluctuations and the principal rifting events that controlled basin evolution. Rift-stage boundaries follow Harding's (1984) classification. The figure has been modified from multiple published sources (Albriki et al. 2021).

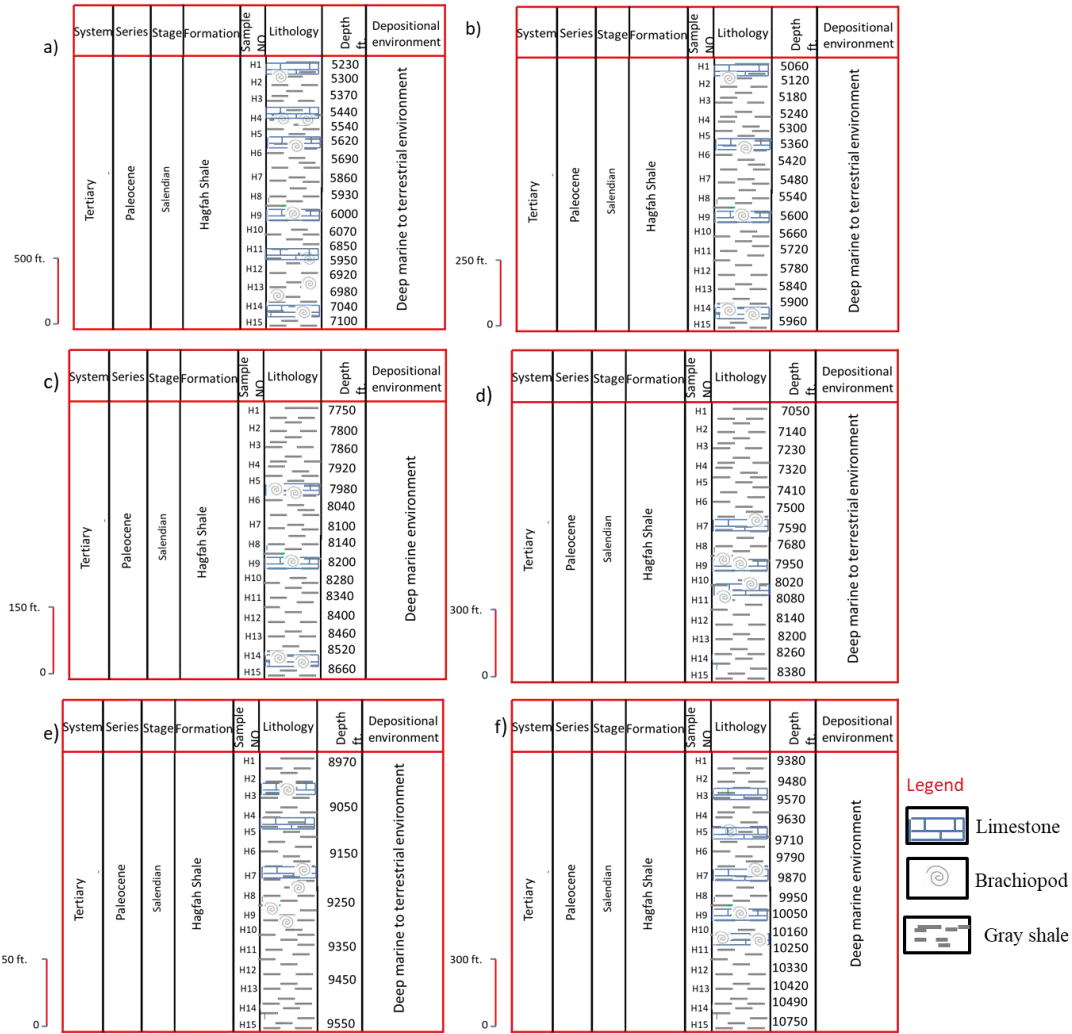


Fig. 4. Lithostratigraphy columns of the investigated wells: a) well F12-20, b) well P1-6, c) well EEE1-6, d) well D194, e) well OO1-6, and f) well K1-12

3. Methodology

The dataset used in this work was provided by Sirte Oil Company, El-Brega, Libya. The company collected, documented, and processed all samples throughout drilling operations. Bagged ditch-cutting samples from the Sirte Basin's Hagfah Shale interval were used in the investigation. A total of 83 cutting samples were selected to represent the source-rock intervals of the Hagfah Shale across several wells and structural settings within the study area (Table 1). The samples were taken from the wells and depth intervals described below. All samples underwent a series of preparation steps to minimize contamination and ensure analytical accuracy. The ditch cuttings were thoroughly cleaned with tap water to remove drilling mud and other contaminants. The cleaned samples were then dried at 80°C to eliminate any organic drilling additives. Following drying, each sample was cleaned with cold dichloromethane (DCM) to remove any residual hydrocarbons that could affect geochemical measurements. The samples were then air-dried and mechanically crushed into a fine powder with a particle size of 100 mesh or smaller.

Representative splits of the powdered material were then prepared for TOC measurement and Rock-Eval pyrolysis. TOC determination was done using a LECO SC-344 carbon analyzer with an infrared detector. In this process, organic carbon is oxidized to CO₂, which is detected with the infrared detector. The results of the TOC analyses show the organic content of the shale samples, which is one of the major parameters in source rock evaluation.

A Rock-Eval II pyrolysis device was used, which included a flame ionization detector (FID) and a thermal conductivity detector (TCD). Each measurement used around 100 mg of powdered material. The analytical technique began with an isothermal stage at 300 °C for 3 min, thereby releasing free hydrocarbons (S₁). Thermally cracked hydrocarbons (S₂) and carbon dioxide (S₃) were produced and measured after increasing the temperature to 600 °C at a rate of 25 °C per minute.

Geochemical data from TOC % and Rock-Eval pyrolysis analyses were used to evaluate several key aspects of the Hagfah Shale's source-rock characteristics, including organic matter abundance and quality, kerogen type and hydrocarbon generation potential, thermal maturity, depositional environment, and unconventional hydrocarbon resource potential. These indicators provide a comprehensive assessment of petroleum source-rock properties and the hydrocarbon potential of the Hagfah Shale interval in the Sirte Basin. The Rock-Eval analysis that was used in this work includes: S₁: free hydrocarbons present in the rock, S₂: hydrocarbons generated from thermal cracking of kerogen, S₃: CO₂ released during pyrolysis, Tmax: temperature at maximum hydrocarbon generation, Hydrogen Index (HI), and Production Index (PI). These parameters were used to evaluate organic matter richness, kerogen type, and thermal maturity of the Hagfah Shale samples.

Structural Domain	Well	Depth Interval (ft)	Thickness (ft)
Dahra Hofra Platform	F12-20	5230–7100	1870
Meanzel Ridge	P1-6	5060–5960	900
Jahama Platform	EEE1-6	7750–8660	910
Zaltan Platform	D1-94	7050–8380	1330
Hateiba Ridge	OO1-6	8970–9550	580
Ajdabiya Trough	K1-12	9380–10750	1370

Table 1: Distribution and thickness of the Hagfah Shale in the studied wells.

4. Results and Discussion

4.1. Geochemical techniques

Several factors are used to assess source rock characteristics, including the quantity and quality of organic matter (TOC%), hydrocarbon generation potential (e.g., S₁ and S₂), and the type of organic matter (kerogen). Furthermore, thermal maturity is evaluated to determine the level of organic matter transformation and its capacity for hydrocarbon generation.

228 Table 2. Geochemical (Rock–Eval) data for the Hagfah Shale in the Dahra Hofra Platform (Well F12-
229 20).

Depth	S ₁	S ₂	S ₃	PI	S ₂ /S ₃	TOC%	T _{max} °C	HI	OI	RO%	OSI
5230-5300	0.05	0.1	0.5	0.33	0.2	0.25	416	40.0	200.0	0.318	20.0
5300-5370	0.07	0.15	0.52	0.32	0.29	0.25	422	60.0	208.0	0.426	28.0
5370-5440	0.06	0.12	0.53	0.33	0.23	0.25	423	48.0	212.0	0.444	24.0
5440-5540	0.08	0.13	0.52	0.32	0.25	0.21	423	61.9	247.6	0.444	38.1
5540-5620	0.07	0.15	0.53	0.32	0.28	0.27	418	55.6	196.3	0.354	25.9
5620-5690	0.07	0.17	0.48	0.32	0.35	0.2	423	85.0	240.0	0.444	35.0
5690-5860	0.07	0.2	0.46	0.26	0.43	0.28	424	71.4	164.3	0.462	25.0
5860-5930	0.07	0.2	0.59	0.26	0.34	0.4	424	50.0	147.5	0.462	17.5
5930-6000	0.09	0.26	0.56	0.21	0.46	0.43	428	60.5	130.2	0.534	20.9
6000-6070	0.08	0.37	0.61	0.2	0.61	0.46	423	80.4	132.6	0.444	17.4
6070-6170	0.16	0.28	0.72	0.22	0.39	0.42	427	66.7	171.4	0.516	38.1
6850- 6920	0.19	0.49	0.78	0.25	0.63	0.5	424	98.0	156.0	0.462	38.0
6920-6980	0.12	0.99	0.58	0.16	1.71	0.7	432	141.4	82.9	0.606	17.1
6980-7040	0.17	0.68	0.38	0.15	1.79	0.6	432	113.3	63.3	0.606	28.3
7040-7100	0.15	0.95	0.45	0.15	2.11	0.63	424	150.8	71.4	0.462	23.8

230

231 Table 3: Geochemical (Rock–Eval) data for the Hagfah Shale in the Meanzel Ridge (Well P1-6)

232

Depth	S ₁	S ₂	S ₃	PI	S ₂ /S ₃	TOC%	T _{max} °C	HI	OI	RO%	OSI
5060-5120	0.13	0.8	0.5	0.14	1.6	0.54	420	148.15	92.59	0.39	24.07
5120-5180	0.08	0.25	0.61	0.22	0.4	0.33	430	75.76	184.85	0.57	24.24
5180-5240	0.07	0.27	0.35	0.24	0.8	0.31	423	87.10	112.90	0.444	22.58
5240-5300	0.07	0.22	0.37	0.29	0.6	0.32	423	68.75	115.63	0.444	21.88
5300-5360	0.11	0.17	0.34	0.41	0.5	0.36	424	47.22	94.44	0.462	30.56
5360-5420	0.13	0.2	0.38	0.39	0.5	0.38	446	52.63	100.00	0.858	34.21
5420-5480	0.12	0.27	0.41	0.31	0.7	0.34	444	79.41	120.59	0.822	35.29
5480-5540	0.13	0.3	0.43	0.29	0.7	0.24	424	125.00	179.17	0.462	54.17
5540-5600	0.11	0.27	0.41	0.23	0.7	0.27	423	100.00	151.85	0.444	40.74
5600-5660	0.08	0.27	0.34	0.26	0.8	0.33	427	81.82	103.03	0.516	24.24
5660-5720	0.1	0.29	0.41	0.24	0.7	0.33	428	87.88	124.24	0.534	30.30
5720-5780	0.1	0.37	0.29	0.23	1.3	0.34	427	108.82	85.29	0.516	29.41
5780-5840	0.08	0.27	0.41	0.3	0.7	0.4	428	67.50	102.50	0.534	20.00
5840-5900	0.08	0.19	0.42	0.28	0.5	0.37	429	51.35	113.51	0.552	21.62
5900-5960	0.13	0.33	0.33	0.22	1.0	0.48	429	68.75	68.75	0.552	27.08

233

234 Table 4: Geochemical (Rock–Eval) data for the Hagfah Shale in the Jahama Platform (Well EEE1-6)

Depth	S ₁	S ₂	S ₃	PI	S ₂ /S ₃	TOC%	T _{max} °C	HI	OI	RO%	OSI
7750-7800	0.48	1.36	0.41	0.26	3.32	0.46	428	295.65	295.65	0.53	104.35
7800-7860	0.96	1	0.62	0.49	1.61	0.42	430	238.10	238.10	0.57	228.57
7860-7920	0.45	0.98	0.48	0.31	2.04	0.58	428	168.97	168.97	0.53	77.59
7920-7980	0.42	0.96	0.47	0.3	2.04	0.56	428	171.43	171.43	0.53	75.00
7980-8040	0.41	0.61	0.49	0.4	1.24	0.49	428	124.49	124.49	0.53	83.67
8040-8100	0.25	0.45	0.5	0.34	0.90	0.48	430	93.75	93.75	0.57	52.08
8100-8140	0.29	0.61	0.44	0.35	1.39	0.55	428	110.91	110.91	0.53	52.73
8140-8200	0.25	0.69	0.48	0.36	1.44	0.48	420	143.75	143.75	0.39	52.08
8200-8280	0.29	0.37	0.58	0.36	0.64	0.47	426	78.72	78.72	0.50	61.70
8280-8340	0.34	0.56	0.46	0.34	1.22	0.36	432	155.56	155.56	0.61	94.44
8340-8400	0.38	0.37	0.55	0.31	0.67	0.35	432	105.71	105.71	0.61	108.57
8400-8460	0.19	0.53	0.28	0.3	1.89	0.17	435	311.76	311.76	0.66	111.76
8460-8520	0.25	0.59	0.4	0.33	1.48	0.34	432	173.53	173.53	0.61	73.53
8520-8580	0.16	0.69	0.8	0.32	0.86	0.45	432	153.33	153.33	0.61	35.56
8580-8660	0.28	0.42	0.59	0.34	0.71	0.36	431	116.67	116.67	0.59	77.78

235

236 Table 5: Geochemical (Rock–Eval) data for the Hagfah Shale in the Zaltan Platform (Well D194)

Depth	S ₁	S ₂	S ₃	PI	S ₂ /S ₃	TOC%	T _{max} °C	HI	OI	RO%	OSI
7050-7140	0.05	0.53	0.42	0.09	1.26	0.47	437	112.8	89.36	0.70	10.64
7140-7230	0.07	0.33	0.41	0.18	0.80	0.37	431	89.2	110.81	0.59	18.92
7230-7320	0.06	0.23	0.37	0.21	0.62	0.31	427	74.2	119.35	0.52	19.35
7320-7410	0.05	0.17	0.38	0.23	0.45	0.34	429	50.0	111.76	0.55	14.71
7410-7500	0.08	0.19	0.39	0.3	0.49	0.22	427	86.4	177.27	0.52	36.36
7500-7590	0.04	0.17	0.35	0.21	0.49	0.31	434	54.8	112.90	0.64	12.90
7590-7680	0.05	0.15	0.31	0.19	0.48	0.44	439	34.1	70.45	0.73	11.36
7680-7950	0.06	0.21	0.44	0.19	0.48	0.49	438	42.9	89.80	0.71	12.24
7950-8020	0.04	0.25	0.46	0.15	0.54	0.37	436	67.6	124.32	0.68	10.81
8020-8080	0.03	0.22	0.45	0.19	0.49	0.35	434	62.9	128.57	0.64	8.57
8080-8140	0.04	0.13	0.42	0.24	0.31	0.4	433	32.5	105.00	0.62	10.00
8140-8200	0.05	0.16	0.45	0.26	0.36	0.33	436	48.5	136.36	0.68	15.15
8200-8260	0.03	0.14	0.38	0.29	0.37	0.22	440	63.6	172.73	0.75	13.64
8260-8320	0.04	0.13	0.45	0.2	0.29	0.32	444	40.6	140.63	0.82	12.50
8320-8380	0.05	0.11	0.46	0.29	0.24	0.36	440	30.6	127.78	0.75	13.89

238 Table 6: Geochemical (Rock–Eval) data for the Hagfah Shale in the Hateiba Ridge (Well OO1-6)

Depth	S ₁	S ₂	S ₃	PI	S ₂ /S ₃	TOC %	T _{max} °C	HI	OI	OSI
8970-9000	1.3	0.72	0.48	0.65	1.5	0.72	402	100	66.67	180.556
9050-9100	1	0.69	0.47	0.6	1.47	0.71	370	97.18	66.20	140.845
9150-9200	0.76	0.7	0.51	0.52	1.37	0.69	357	101.45	73.91	110.145
9250-9300	0.7	0.45	0.44	0.61	1.02	0.74	375	60.81	59.46	94.5946
9350-9400	0.48	0.43	0.55	0.53	0.78	0.57	366	75.44	96.49	84.2105
9450-9500	0.45	0.37	0.52	0.55	0.71	0.67	373	55.22	77.61	67.1642
9500-9550	0.54	0.4	0.47	0.47	0.85	0.67	361	59.70	70.15	80.597

240 Table 7: Geochemical (Rock–Eval) data for the Hagfah Shale in the Ajdabiya Trough (Well K1-12)

Depth	S ₁	S ₂	S ₃	PI	S ₂ /S ₃	TOC%	T _{max} °C	HI	OI	RO%	OSI
9380-9470	0.15	0.81	0.35	0.16	2.31	0.35	424	231.43	100	0.462	42.86
9480-9550	0.38	1	0.6	0.27	1.67	0.47	432	212.77	127.66	0.606	80.85
9570-9620	0.25	0.93	0.5	0.21	1.86	0.52	433	178.85	96.15	0.624	48.08
9630-9692	0.22	1.59	0.47	0.12	3.38	0.76	437	209.21	61.84	0.696	28.95
9710-9780	0.18	1.19	0.45	0.13	2.64	0.76	437	156.58	59.21	0.696	23.68
9790-9860	0.18	1.33	0.66	0.12	2.02	0.77	437	172.73	85.71	0.696	23.38
9870-9942	0.27	1	0.38	0.2	2.63	0.55	437	181.82	69.09	0.696	49.09
9950-10040	0.29	1.15	0.55	0.2	2.09	0.65	434	176.92	84.62	0.642	44.62
10050-10150	0.21	1.28	0.38	0.14	3.37	0.33	434	387.88	115.15	0.642	63.64
10160-10240	0.23	1.23	0.46	0.16	2.67	0.62	434	198.39	74.19	0.642	37.10
10250-10320	0.18	0.87	0.44	0.17	1.98	0.51	433	170.59	86.27	0.624	35.29
10330-10410	0.17	0.16	0.42	0.1	0.38	0.47	432	34.04	89.36	0.606	36.17
10420-10490	0.25	1.26	0.45	0.15	2.80	0.83	435	151.81	54.22	0.66	30.12
10490-10560	0.35	1	0.37	0.15	2.70	0.53	435	188.68	69.81	0.66	66.04
10660-10750	0.4	1.1	0.45	0.24	2.44	0.76	436	144.74	59.21	0.678	52.63

4.1.1 Quality of organic matter and type of organic matter

The total organic carbon (TOC %) content of rock samples is a key parameter for evaluating the potential of sediments as petroleum source rocks. A widely used classification system was proposed by Peters (1986) and later refined by Peters and Cassa (1994), integrating TOC % with Rock–Eval pyrolysis parameters (S₁ and S₂).

Based on the data in Tables 2-7, the TOC values of the Hagfah Shale across different structural settings generally indicate low organic richness. In the Dahra Platform (Well F12-20), TOC% ranges from 0.21 to 0.60%, whereas in the Meanzel Ridge (Well P1-6), it ranges from 0.31 to 0.54%. Similarly, the Zaltan Platform (Well D194) shows TOC % values between 0.22 and 0.49 wt.%, and the Jahama Platform (Well EEE1-6) ranges from 0.16 to 0.58 %. These values indicate predominantly poor source rock quality (Fig. 5a).

In contrast, slightly higher TOC wt.% values are observed in the Hateiba Ridge 9 (Well OO1-6), ranging from 0.57 to 0.72 %, and in the Ajdabiya Trough (Well K1-12), where TOC % ranges from 0.35 to 0.83 % (Fig. 5a). These intervals suggest poor to fair source rock, with occasional improvement in organic richness. This interpretation is further supported by the bivariate plot of TOC % vs. S₂ (Fig. 5b) (Dembicki 2009). In general, the Hagfah Shale in the investigated wells is characterized by poor to marginal source-rock quality (Peters and Cassa 1994), with only limited intervals approaching fair potential under standard TOC % classification schemes. According to S₁ results, the Hagfah Shale in the

Hateiba Ridge (Well OO1-6) ranges from 0.45 to 1.3 mg HC/g rock, indicating primarily fair source rock quality (Peters and Cassa 1994). In contrast, the remaining wells have S_1 values below 0.5 mg HC/g rock, indicating poor free hydrocarbon content (Fig. 6a). S_2 levels in all examined samples from the studied wells were less than 2.5 mg HC/g rock, indicating poor generative potential (Fig. 6b). This shows that, despite minor differences in S_1 , the Hagfah Shale's total hydrocarbon-generating capacity is limited. The S_1 vs. TOC % plot (Fig. 7) distinguishes between nonindigenous (allochthonous) and indigenous (autochthonous) hydrocarbons (Rabbani and Kamali 2005; Ghorri and Haines 2007). This relationship indicates that the Hagfah Shale samples from all wells contain autochthonous hydrocarbons, suggesting that the oil in the studied wells has not migrated.

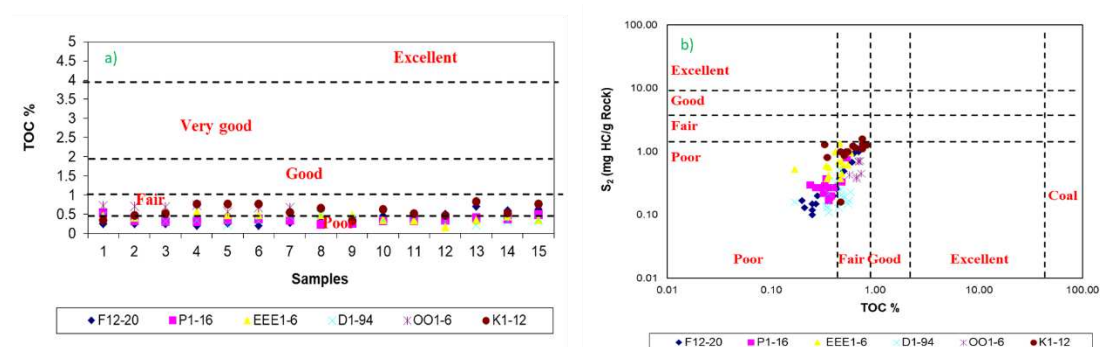


Fig. 5: a) Classification of TOC % in the investigated wells (Peters and Cassa 1994) and b) Plot of TOC % vs. S_2 revealing the organic matter quality for the Hagfah Shale (modified from Dembicki 2009).

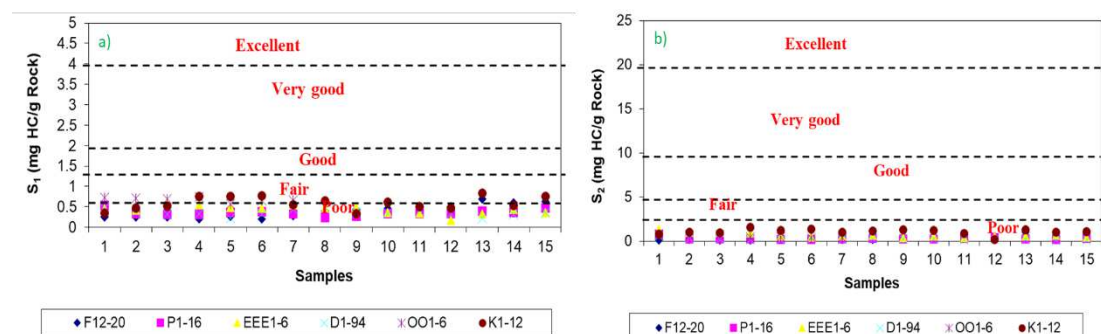


Fig. 6: a) S_1 Parameter grading and organic matter quality, and b) S_2 parameter grading and organic matter quality in the studied wells (Peters and Cassa 1994).

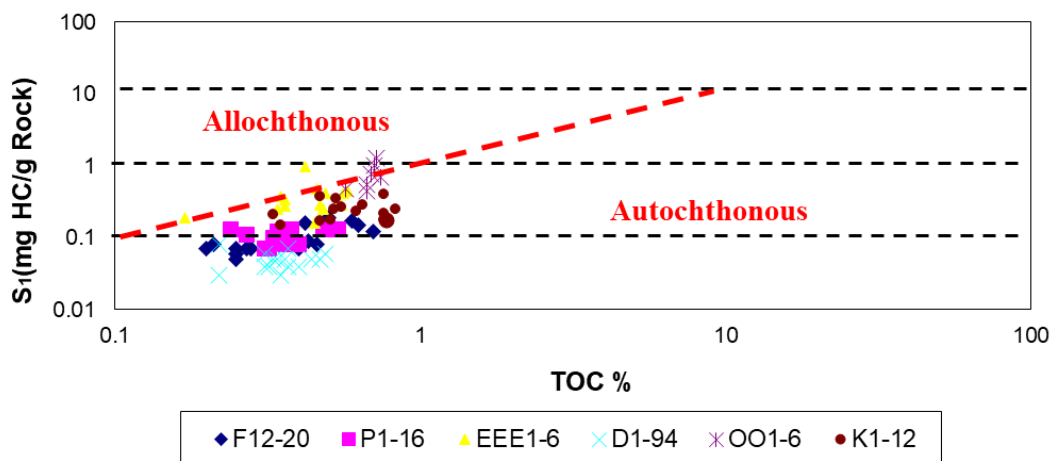


Fig. 7: Relationship between TOC % and S_1 showing autochthonous kerogen in the studied wells (Rabbani and Kamali 2005).

The classification of kerogen based on Hydrogen Index (HI) values follows the scheme proposed by Peters and Cassa (1994). According to this classification, kerogen types are defined as follows: Type I (HI > 600 mg HC/g TOC, oil-prone), Type II (HI = 300–600 mg HC/g TOC, mainly oil-prone), Type II/III (HI = 200–300 mg HC/g TOC, mixed oil- and gas-prone), Type III (HI = 50–200 mg HC/g TOC, gas-prone), and Type IV (HI < 50 mg HC/g TOC, non-generative or inert). In this work, we used the Longford and Blanc-Valleron (1990) and Bordenave et al. (1993) kerogen type diagrams, which plot TOC (%) vs. S_2 . The HI-based classification of the analyzed samples (Fig. 8a) indicates that the Hagfah Shale in the Dahra Hofra Platform (Well F12-20), Meanzel Ridge (Well P1-6), and Hateiba Ridge (Well OO1-6) is predominantly characterized by Type III kerogen, indicating gas-prone organic matter. The Hagfah shale on the Zaltan Platform (Well D194) contained Type III with minor Type IV, indicating gas-prone, dry-gas organic matter. In contrast, the Jahama Platform (Well EEE1-6) and the Ajdabiya Trough (Well K1-12) exhibit mainly Type III kerogen with minor contributions from Type II/III, suggesting a predominantly gas-prone system with limited oil-prone characteristics. The relationship between TOC wt.% and S_2 further supports the above interpretation (Fig. 8b), as the generally low S_2 values associated with low TOC wt.% indicate limited hydrocarbon-generation potential.

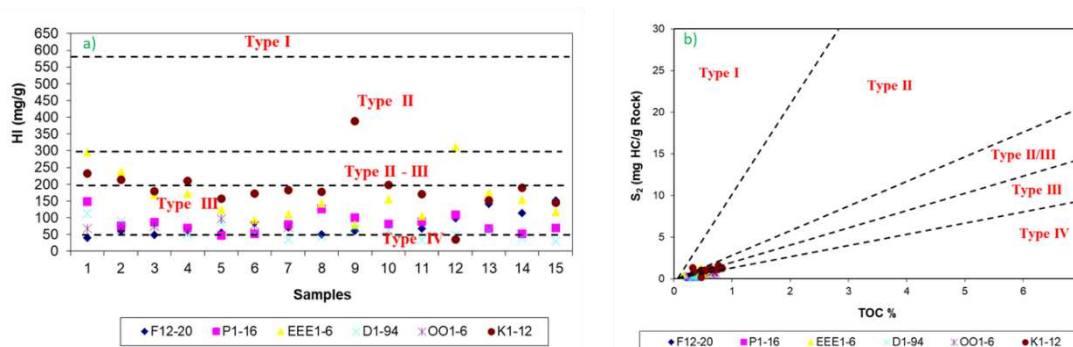


Fig. 8: a) Classification of HI (Peters and Cassa 1994). b) Plot TOC % vs. S_2 , revealing the kerogen types of Hagfah Shale in the studied wells (modified from Longford and Blanc-Valleron 1990).

4.1.2. Generating potentialities

The hydrocarbon generation potential of a source rock can be evaluated using Rock–Eval pyrolysis data. The genetic potential (GP) is defined as the sum of S_1 and S_2 values ($GP = S_1 + S_2$). According to Hunt (1996), source rocks with GP values < 2 mg HC/g rock are classified as having poor generation potential; those between 2 and 5 mg HC/g rock as fair; between 5 and 10 mg HC/g rock as good; and values > 10 mg HC/g rock as very good. The relationship between TOC % and GP ($S_1 + S_2$) supports this classification (El Nady et al. 2016). The results indicate that the studied samples can be classified as having poor hydrocarbon generation potential, as most values fall within the poor category (Fig. 9). Furthermore, the TOC % vs. $S_1 + S_2$ and TOC % vs. HI plots show that the shale samples are predominantly within the poor potential field (Fig. 10a and b), confirming their limited generative capacity.

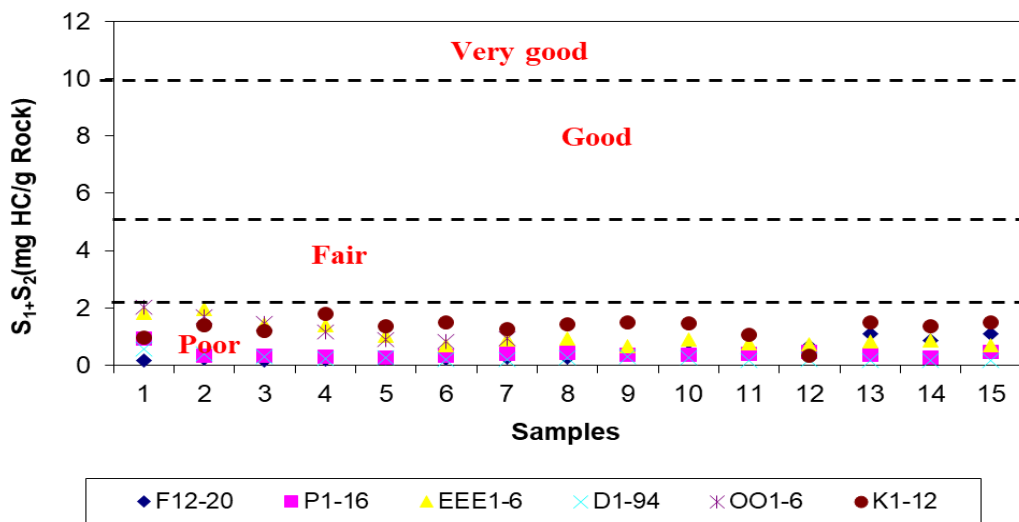


Fig. 9: The hydrocarbon generation potential S_1+S_2 of investigated samples (Hunt 1996).

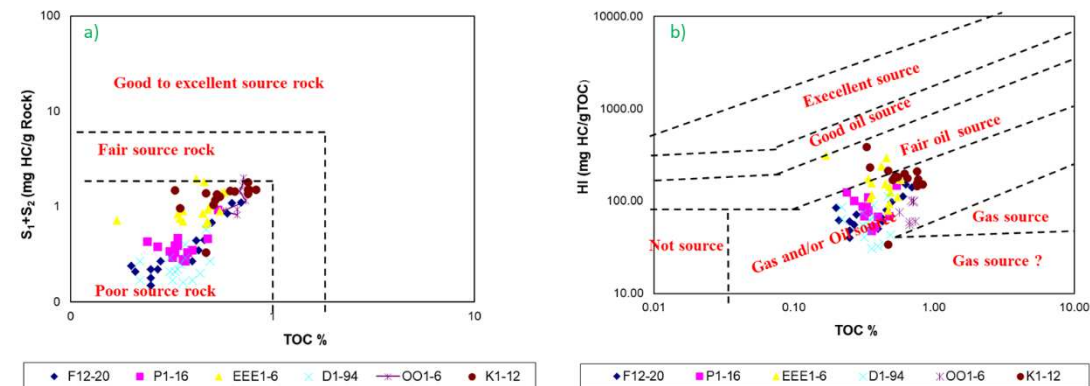


Fig. 10: Plot of the genetic potential ($S_1 + S_2$) vs. TOC % for potential source rock (El Nady et al. 2016).
b) Plot of the TOC % vs. HI in the studied wells (Jackson et al. 1985).

4.1.3. Thermal maturity based on production index (PI) and Tmax °C

Thermal maturity is an important characteristic for determining the hydrocarbon production potential of source rocks because it indicates the extent of organic material transformation during burial and heating. Rock-Eval pyrolysis provides key indicators of thermal maturity, particularly Tmax (°C; the temperature at which maximal hydrocarbon formation occurs) and the Production Index ($PI = S_1 / (S_1 + S_2)$) (Peters 1986; Hunt 1996). Tmax °C is commonly used to assess thermal maturity, with values below 435°C indicating immature organic matter, values between 435°C and 455°C corresponding to the oil window, and values above 455°C indicating late maturity to overmaturity (Peters & Cassa 1994). Similarly, the Production Index (PI) increases with maturity; values less than 0.1 indicate immature conditions, values between 0.1 and 0.4 indicate active hydrocarbon generation, and values larger than 0.4 indicate advanced maturity or potential migrating hydrocarbons (Hunt 1996). A cross-plot of PI vs. Tmax °C is commonly used to assess maturity trends and discriminate among immature, mature, and overmature source rocks. In the present study, based on Tmax°C classification, the Hagfah shale in the Zaltan Platform (Well D194) and the Ajdabiya Trough (Well K1-12) fall within the early mature stage (oil window), whereas the other studied wells are generally immature to marginally mature (Fig. 11a). Production Index (PI) statistics further confirm this finding. The Ajdabiya Trough (Well K1-12) falls within the prospective migrated hydrocarbon field, implying hydrocarbon migration or contamination impacts. In contrast, the other wells are mainly located within the active hydrocarbon-generation zone, indicating early-stage in situ hydrocarbon generation (Fig. 11b). Well, K1-12 shows evidence of increased maturity or hydrocarbon migration; the overall thermal maturity of the Hagfah Shale across the study region is low to moderate. This is consistent with the generally poor or marginal hydrocarbon-generation potential inferred from TOC % and S_2 data. A cross-plot of PI vs. Tmax °C supports the above interpretation (Fig. 12).

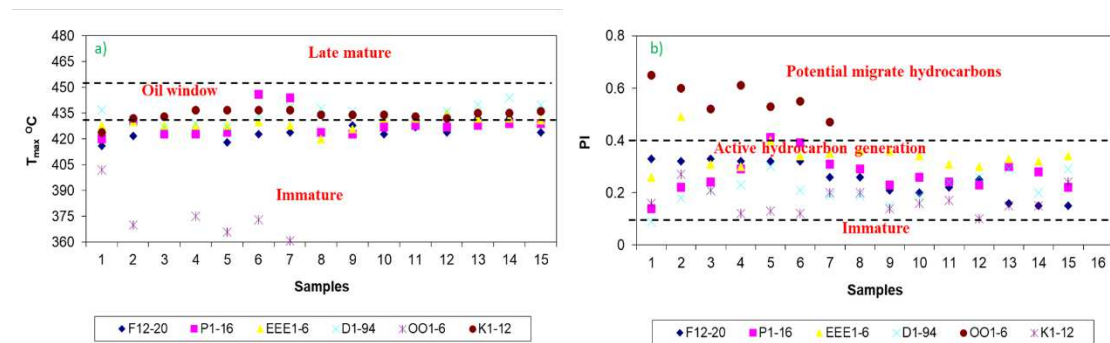


Fig. 11: Classification of thermal maturity Tmax °C (Peters and Cassa 1994), b) Classification of thermal maturity based on PI (Hunt 1996).

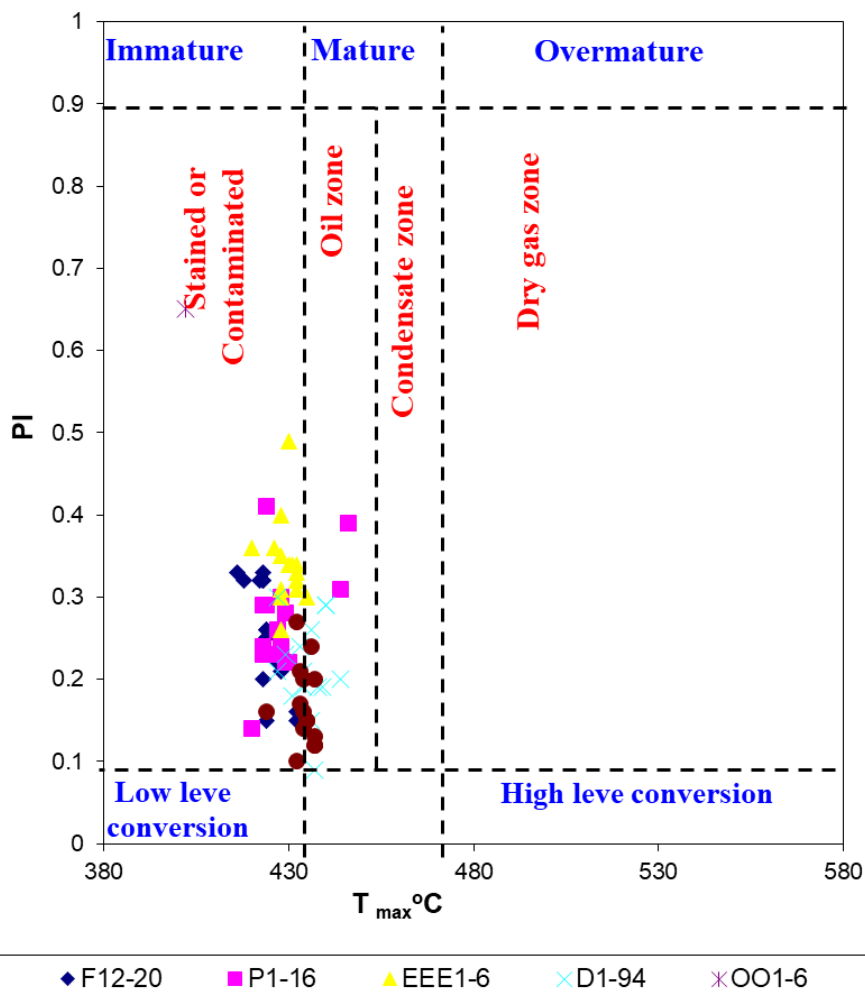


Fig. 12: Relationship of Tmax °C vs. PI for thermal maturity of the Hagfah Shale in the investigated wells (modified from Waples 1985)

4.1.4 Cluster analysis of the Hagfah Shale in the investigated wells

Cluster analysis partitions a sample into homogeneous classes, yielding operational classification. In this work, we used hierarchical clustering. This is the primary statistical strategy for identifying similar clusters of cases based on measurable characteristics. The method divides the examples into groups and sequentially merges them, reducing the number of clusters until only one remains. The clustering approach groups things based on their dissimilarity or distance. The SPSS application calculates 'distances' between data points using specified variables. SPSS allows for the creation of a dendrogram, a hierarchical tree diagram that depicts linkage (Edwards et al. 1999; Murtagh and Legendre 2014; El Nady et al. 2015). Hierarchical cluster analysis was applied to the samples to classify the Hagfah Shale into distinct geochemical groups that reflect variations in organic matter characteristics, thermal maturity, and hydrocarbon generation potential (Figs. 13 and 14; Tables 8-13).

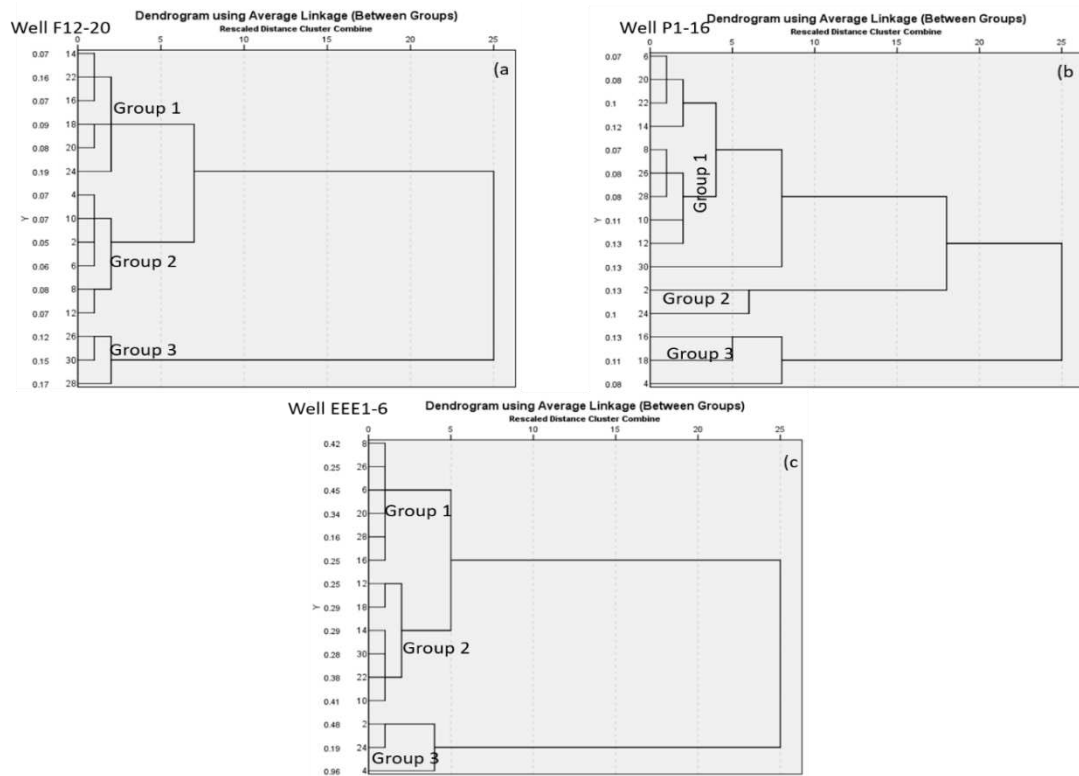


Fig. 13: Hierarchical cluster analysis dendrogram using average linkage (between groups) for a) Well F12-20, b) Well P1-16 and Well EEE1-6.

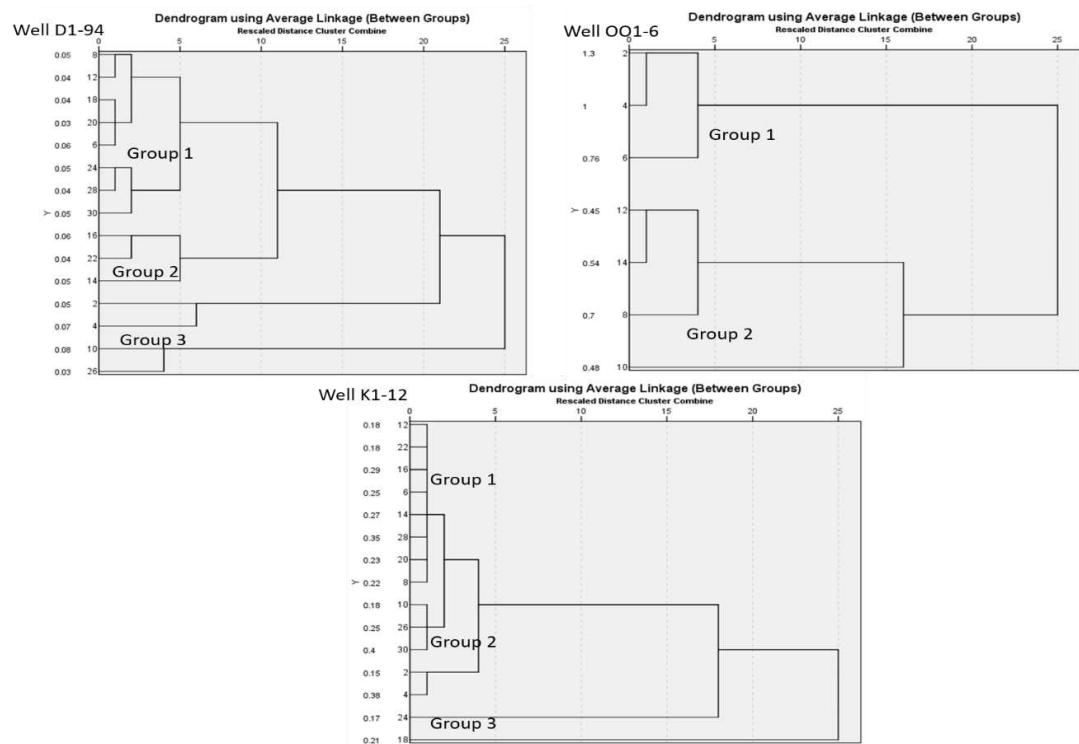


Fig. 14: Hierarchical cluster analysis dendrogram using average linkage (between groups) for a) Well D1-94, b) Well OO1-6, and c) Well K1-12

Table 8: Geochemical characteristics and source rock classification of the Hagfah Shale in Well F12-20

Group	Depth Interval (ft)	Relative Position	Geochemical Characteristics	Source Rock Assessment
I	5860–6920	Middle interval	Transitional zone with relatively uniform geochemical behavior; moderate TOC; similar Rock–Eval parameters	Consistent but poor source rock quality; limited hydrocarbon generation potential
II	5230–5860	Shallow interval	Slightly lower thermal maturity than Group I; lower Tmax; OI = 130–171.4 mg CO ₂ /g TOC; TOC = 0.28–0.50 wt.% with a slight increase with depth	Poor source rock quality and limited hydrocarbon generation potential
III	6980–7100	Deepest interval	Highest thermal maturity; Tmax = 424–432°C; Ro = 0.8–1.1%; entered the oil window; variable organic matter characteristics	Thermally mature but no significant improvement in hydrocarbon generation potential

Table 9: Geochemical characteristics and source rock classification of the Hagfah Shale in Well P1-6

Group	Depth Interval (ft)	Relative Position	Geochemical Characteristics	Source Rock Assessment
I	5060–5660	Shallow to mid-depth	Relatively uniform geochemical properties; low TOC and S ₂ values	Poor source rock quality and limited hydrocarbon generation potential
II	5660–5780	Transitional zone	Slight increase in TOC; S ₂ = 0.27–0.39 mg HC/g rock; HI = 87–108 mg HC/g TOC	Slight improvement in organic richness and generative potential, but overall poor source rock quality
III	5780–5960	Deepest interval	Higher thermal maturity; Tmax = 428–429°C; S ₂ /S ₃ = 0.5–1.0; Ro ≈ 0.5% (early mature)	Early-mature source rock with limited hydrocarbon generation potential

Table 10: Geochemical characteristics and source rock classification of the Hagfah Shale in Well EEE1-6

Group	Depth Interval (ft)	Relative Position	Geochemical Characteristics	Source Rock Assessment
I	7750–8100	Shallow	Tmax = 428–430°C; HI = 93–295 mg HC/g TOC mixed Type II/III to Type III kerogen	Gas-prone to minor oil-prone source rock with relatively higher hydrogen richness
II	8100–8460	Middle interval	Moderate variation in TOC; Tmax = 426–435°C; Ro = 0.33–0.66%; progressive increase in thermal maturity with depth	Increasing thermal maturity with moderate source rock quality
III	8460–8660	Deepest interval	Greater geochemical variability relatively higher S ₃ values (0.4–0.8 mg CO ₂ /g rock continued increase in thermal maturity	Early-mature source rock with limited hydrocarbon generation potential

Table 11: Geochemical characteristics and source rock classification of the Hagfah Shale in Well D1-94

Group	Depth Interval (ft)	Relative Position	Geochemical Characteristics	Source Rock Assessment
I	7050–7410	Shallow	TOC = 0.22–0.47 wt.%; Ro = 0.52–0.70%; relatively uniform geochemical properties; predominantly Type III kerogen	Gas-prone source rock with poor organic richness and limited hydrocarbon generation potential
II	7950–8200	Middle interval	Tmax = 434–439°C; Ro = 0.64–0.84%; HI = 42–64 mg HC/g TOC; more thermally mature than Group I	Degraded organic matter dominated by mixed Type IV–III kerogen with poor generative potential
III	8200–8300	Deep interval	Highest thermal maturity; Tmax = 440–444°C; Ro = 0.75–0.82%; TOC = 0.22–0.36 wt.%	Most mature interval, dominated by inert Type IV kerogen with negligible hydrocarbon generation potential

Table 12: Geochemical characteristics and source rock classification of the Hagfah Shale in Well OO1-6

Group	Depth Interval (ft)	Relative Position	Geochemical Characteristics	Source Rock Assessment
I	8970–9200	Shallow	TOC = 0.69–0.72 wt.%; S ₂ /S ₃ = 1.37–1.50; relatively low Tmax	Better organic richness and hydrocarbon generation potential than Group 2, although the organic matter
II	9200–9550	Deep interval	Lower TOC and lower S ₂ /S ₃ ratio	Poorer organic richness and reduced hydrocarbon generation potential compared to Group 1

Table 13: Geochemical characteristics and source rock classification of the Hagfah Shale in Well K1-12

Group	Depth Interval (ft)	Relative Position	Geochemical Characteristics	Source Rock Assessment
I	9839–10040	Shallow	HI = 172–387 mg HC/g TOC; Tmax = 432–437°C	Mixed Type II–III and Type III kerogen with both oil- and gas-prone potential; organic matter is in the early mature stage
II	10050–10410	Middle interval	TOC = 0.47–0.62 wt.%; Tmax = 432–434°C	Predominantly Type III kerogen with limited TOC variation; thermally immature and mainly gas-prone.
III	10420–10750	Deep interval	TOC = 0.53–0.83 wt.%; Tmax = 435–436°C	Higher organic richness and maturity within the oil window, indicating favorable conditions for hydrocarbon generation

4.1.5. Paleo-depositional and redox conditions of the Hagfah Shale

The depositional environments indicated by Jones's (1987) HI-OI categorization provide important insights into the variety of organic matter types, preservation conditions, and overall source rock quality across the investigated wells. The Hagfah Shale found on the Dahra Hofra Platform (Well F12-20), Meanzel Ridge (Well P1-6), Zaltan Platform (Well D1-94), and Hateiba Ridge (Well OO1-6) is primarily associated with mixed Zone D-CD conditions. These zones show deposition in predominantly oxidizing to transitional settings, spanning terrestrial to deep-oceanic environments near orogenic highs, where variable redox conditions influenced organic matter preservation (Tyson 1995; Peters and Cassa 1994; Awadh 2025). Zone D exhibits highly oxidizing, terrestrially affected settings, whereas Zone CD reflects transitional conditions with considerable marine influence (Jones 1987). In contrast, the Hagfah Shale in the Jahama Platform (Well EEE1-6) was deposited at moderate sedimentation rates in relatively reducing conditions (Fig. 15), corresponding primarily to Zone CD, which reflects deeper-marine environments with higher organic matter preservation. Similarly, the Ajdabiya Trough (Well K1-12) shows deposition under moderate sedimentation in a reducing environment, implying better conditions for organic matter preservation than in more oxidized settings (Demaïson and Moore 1980; Fares et al. 2026). The kerogen distribution based on the HI classification supports these environmental interpretations. The Hagfah Shale in Dahra Hofra Platform (Well F12-20), Meanzel Ridge (Well P1-6), and Hateiba Ridge (Well OO1-6) is dominated by Type III kerogen, indicating that the organic matter is primarily gas-prone and derives from terrestrial input (Peters et al. 2005). Type III kerogen with little Type IV is observed on the Zaltan Platform (Well D1-94), indicating gas-prone to inert organic materials with a higher degree of oxidation (Tissot and Welte 1984). In contrast, the Jahama Platform (Well EEE1-6) and Ajdabiya Trough (Well K1-12) contain primarily Type III kerogen with minor Type II/III contributions, indicating a mixed terrestrial-marine origin and gas-prone characteristics with limited oil-generating potential (Hunt 1996; Peters et al. 2005). In general, the integrated geochemical analysis and depositional environments show that variations in sedimentation rates, redox conditions, and proximity to terrestrial input sources have a primary influence on organic matter type and preservation, ultimately governing the Hagfah Shale's hydrocarbon generation potential across different structural settings (Tyson 1995; Tissot and Welte 1984).

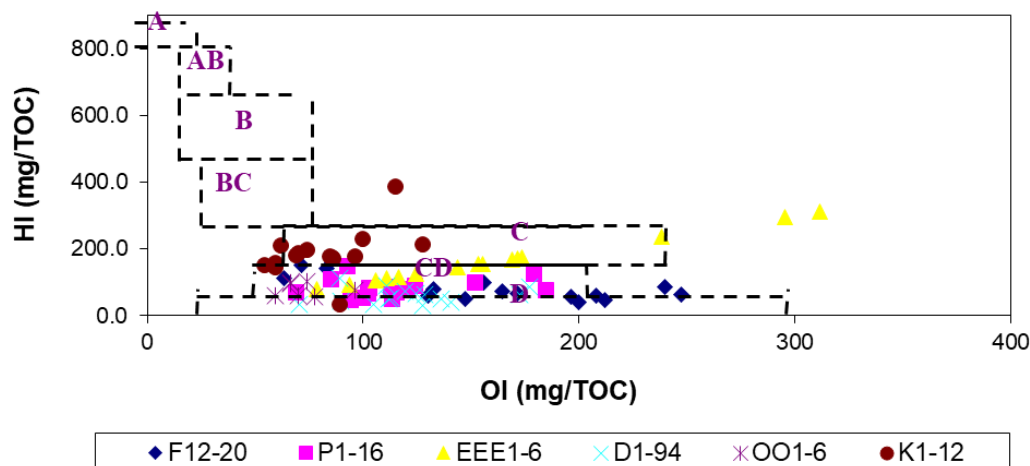


Fig. 15: Jones' (1987) diagram illustrating the depositional environments of organic matter in the studied wells. Zone (A) corresponds to highly reducing lacustrine settings; Zone (AB) represents reducing, prograding marine environments; Zone (B) reflects relatively reducing marine–lacustrine conditions; Zone (BC) characterizes mixed marine–terrestrial environments with high sedimentation rates under relatively oxidizing conditions; Zone (C) denotes moderate sedimentation in a reducing environment; Zone (CD) corresponds to deep marine settings adjacent to orogenic hotspots; and Zone (D) represents highly oxidizing, terrestrially influenced environments (Jones 1987).

4.1.6 Oil saturation index of the Hagfah Shale

The Oil Saturation Index ($OSI = S1 \times 100/TOC$) is a key geochemical parameter used to evaluate the number of free hydrocarbons retained within source rocks and potential reservoirs (Jarvie et al. 2007; Jarvie 2012). OSI values below 100 mg HC/g TOC are generally considered indicative of low oil saturation and limited reservoir potential. In contrast, values approaching or exceeding this threshold suggest improved oil retention and potential producibility. The Oil Saturation Index (OSI) results for the Hagfah shale show generally low values (<100 mg HC/g TOC) in the Dahra Hofra Platform (Well F12-20), Meanzel Ridge (Well P1-6), Zaltan Platform (Well D1-94), and Ajdabiya Trough (Well K1-12), indicating low hydrocarbon saturation and limited oil potential. Compared to that, the Jahama Platform (Well EEE1-6) and Hateiba Ridge (Well OO1-6) exhibit intervals with OSI values greater than 100 mg HC/g TOC (Fig. 16), indicating localized hydrocarbon enrichment and improved retention potential (Jarvie et al. 2007; Jiang et al. 2017). The Hagfah Shale's dominance of Type III kerogen, low TOC content, and typically low Oil Saturation Index (OSI) values indicate that it is predominantly gas-prone, has limited shale-oil potential, and can be classified as a poor-to-marginal source rock. Its contribution to the petroleum system is thus likely secondary, producing only trace amounts of hydrocarbons locally. Significant hydrocarbon accumulations are more likely to be caused by migration from more effective source rocks than by in-situ (autochthonous) generation (Jarvie et al. 2007; Tissot and Welte 1984). Therefore, the main finding of this work is that the Hagfah Shale should not be considered a regionally effective petroleum source rock. However, localized intervals within specific

structural domains may have sufficient organic richness and hydrocarbon retention to contribute to the petroleum system.

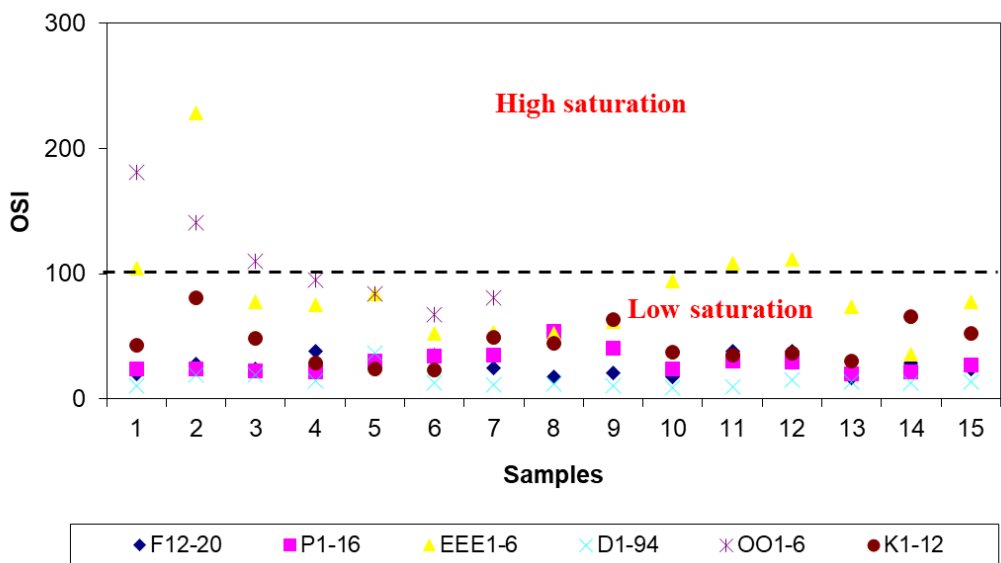


Fig. 16: Classification of oil saturation index of the Hagfah Shale in the investigated wells (Jarvie et al. 2007; Jarvie 2012).

4.1.7. Exploration Implications of the Hagfah Shale

According to geochemical findings, the Hagfah Shale typically exhibits low to fair source-rock quality across all studied structural settings in the Sirte Basin. Primarily Type III kerogen, immature to early-mature thermal conditions, and low Oil Saturation Index (OSI) values, indicating limited hydrocarbon generation, are characteristic of the majority of wells. The Jahama Platform (Well EEE1-6) and Ajdabiya Trough (Well K1-12) have comparatively better source rock features due to higher levels of thermal maturity and organic matter preservation. With all factors considered, the Hagfah Shale is regarded as a moderately gas-prone source rock, with only isolated periods requiring additional investigation and comprehensive basin modeling.

5. Conclusions

This work investigates the Rock–Eval pyrolysis characteristics of the Hagfah Shale through different structural settings within the Sirte Basin in Libya, including Dahra Hofra Platform (Well F12-20), Meanzel Ridge (Well P1-6), Jahama Platform (Well EEE1-6), Zaltan Platform (Well D194), Hateiba Ridge (Well OO1-6), and the Ajdabiya Trough (Well K1-12).

The results show that the TOC % values of the Hagfah Shale are generally low across the Dahra Hofra Platform (Well F12-20), Meanzel Ridge (Well P1-6), Zaltan Platform (Well D194), and Jahama Platform (Well EEE1-6), indicating low organic matter concentration and hydrocarbon-generation potential. In

contrast, the Hagfah Shale in the Hateiba Ridge (Well OO1-6) and Ajdabiya Trough (Well K1-12) has slightly higher TOC values, indicating organic richness ranging from poor to fair.

In contrast, the overall hydrocarbon generation potential remains limited. Based on kerogen classification, the Hagfah Shale of the Dahra Hofra Platform (Well F12-20), Meanzel Ridge (Well P1-6), and Hateiba Ridge (Well OO1-6) is primarily composed of Type III kerogen, which indicates gas-prone organic materials in immature to early mature conditions. Similarly, the Zaltan Platform (Well D194) is dominated by Type III kerogen, with very little Type IV, indicating gas-prone to inert organic matter, immature to mature phases, and limited hydrocarbon-generation capacity.

Conversely, the Hagfah Shale in the Jahama Platform (Well EEE1-6) and the Ajdabiya Trough (Well K1-12) are composed primarily of Type III kerogen, with minor Type II/III contributions, indicating gas-prone organic matter with minor oil-prone potential, ranging from immature to early mature. The Hagfah Shale in the Dahra Hofra Platform (F12-20), Meanzel Ridge (P1-6), Zaltan Platform (D194), and Hateiba Ridge (OO1-6) was deposited in mixed (oxic to sub-oxic) conditions, indicating moderate organic matter preservation. On the other hand, the Jahama Platform (EEE1-6) and Ajdabiya Trough (K1-12) were formed under more reducing conditions, indicating deeper marine habitats with improved organic matter preservation.

The Hagfah Shale in the Dahra Hofra Platform (F12-20), Meanzel Ridge (P1-6), Zaltan Platform (D194), and Hateiba Ridge (OO1-6) was deposited under mixed (oxic to sub-oxic) conditions, indicating moderate organic matter preservation, while the Jahama Platform (EEE1-6) and Ajdabiya Trough (K1-12) were deposited under reducing conditions, reflecting deeper marine environments with better organic matter preservation.

The Oil Saturation Index (OSI) values throughout the investigated wells are generally low, indicating poor hydrocarbon saturation and limited shale-oil potential, as hydrocarbons are not sufficiently retained within the source rock.

Funding

No funding.

Use of artificial intelligence

The authors used artificial intelligence tools solely to improve the language and readability of the manuscript.

CRedit authorship contribution statement

Fares F. Fares: Supervision, Project administration, Conceptualization, Software, Formal analysis, Data curation, Writing – review and editing.

481 Mohammed Afkareen: Methodology, Writing – review and editing.

482 Osama A. El Fallah, Abobkar E. Algomati and Faraj S. Faraj: Writing – review and editing.

483 **Data availability**

484 The authors do not have permission to share data.

485 **Acknowledgements**

486 We want to express our sincere gratitude to the Sirte Oil Company, particularly the Exploration
487 Department, for granting permission to access, publish, and share the dataset used in this study, as well
488 as for their continuous support and assistance throughout this work.

489 **References**

490 Abadi AM, van Wees J-D, van Dijk PM, Cloetingh SAPL (2008) Tectonics and subsidence evolution of
491 the Sirte Basin. AAPG Bulletin 92(8):993–1027. <https://doi.org/10.1306/03310806070>

492 Abdalla M, Yang W, Abdelnabi A (2025) Characterization and evolution of a retrograding-prograding
493 deltaic system, NE Sirte Basin, north-central Libya—sequence stratigraphic architecture and controlling
494 factors. Journal of African Earth Sciences 224:105558. <https://doi.org/10.1016/j.jafrearsci.2025.105558>

495 Abdalla M, Yang W, El Ebaidi S (2023a) Sequence stratigraphic architecture, evolution, and geological
496 controls of an Eocene isolated carbonate platform. Journal of African Earth Sciences 201:104884.

497 Abdalla M, Yang W, Shaniba S (2023b) Growth and demise of a Paleocene isolated carbonate platform.
498 AAPG Bulletin 107(10):1723–1752.

499 Abogilila S, Elkhilgi M (2013) Organic geochemical evaluation of Cretaceous source rocks. International
500 Journal of Geosciences 4:700–710. <https://doi.org/10.4236/ijg.2013.44065>

501 Ahlbrandt TS (2001) The Sirte Basin Province of Libya: Sirte-Zelten Total Petroleum System. U.S.
502 Geological Survey Bulletin 2202-F, 29 p. <https://doi.org/10.3133/b2202F>

503 Albriki K, Wang F, Li M, El Zaroug R (2021) Source rock maturity evaluation and its implications for
504 regional petroleum charge, Sirt Basin, Libya: Insights from regional geochemical assessments and
505 modelling study. Journal of African Earth Sciences 176:104114.
506 <https://www.sciencedirect.com/science/article/pii/S1464343X21000157>

507 Albriki K, Wang F, Li M, El Zaroug R, Ali Z (2022) Assessment of the thermal maturation, organofacies,
508 and petroleum generation history of Sirte Shale Formation in Sirt Basin, Libya. J Afr Earth Sci
509 196:104710. <https://doi.org/10.1016/j.jafrearsci.2022.104710>

510 Anketell JM (1996) Structural history of the Sirt Basin and its relationships to the Sabratah Basin and
511 Cyrenaican Platform, northern Libya. In: Salem MJ, El-Hawat AS, Sbata AM (eds) The Geology of Sirt
512 Basin. Vol III. Elsevier, Amsterdam, pp 57–87.

513 Awadh SM (2025) Kerogen type and hydrocarbon generation guide for petroleum exploration: insights
514 from Middle East basins. Iraqi Geol J 58(2B):202–218. <https://doi.org/10.46717/igi.2025.58.2B.14>

- 515 Barr FT, Weegar AA (1972) Stratigraphic nomenclature of Libya. Petroleum Exploration Society of
516 Libya 2:179–191.
- 517 Bordenave ML, Espitalié J, Leplat P, Oudin JL, Vandenbroucke M (1993) Screening techniques for
518 source rock evaluation. In: Bordenave ML (ed) Applied Petroleum Geochemistry. Éditions Technip,
519 Paris, pp 217–278.
- 520 Conant LC, Goudarzi GH (1967) Stratigraphic and tectonic framework of Libya. AAPG Bulletin
521 51(5):719–730. <https://doi.org/10.1306/5D25C0C9-16C1-11D7-8645000102C1865D>
- 522 Demaison GJ, Moore GT (1980) Anoxic environments and oil source bed genesis. AAPG Bulletin
523 64(8):1179–1209. <https://doi.org/10.1306/2F91945E-16CE-11D7-8645000102C1865D>
- 524 Dembicki H Jr (2009) Three common source rock evaluation errors made by geologists during prospect
525 or play appraisals. AAPG Bulletin 93(3):341–356. <https://doi.org/10.1306/10230808076>
- 526 Edwards DS, Zumberge JE, Zumberge JA, Volkman JK (1999) Hydrocarbon source and oil–source rock
527 correlation in the Otway Basin, southeastern Australia. APPEA J
- 528 El Diasty WS, El Beialy SY, Peters KE, El Atfy H, Gheith AM, Agha NN (2016) Organic geochemistry
529 of crude oils and Upper Cretaceous source rocks from Concession 11, West Sirte Basin, Libya. J Pet
530 Geol 39(4):393–413. <https://doi.org/10.1111/jpg.12659>
- 531 El Nady MM, Awad SA, Sharaf LM (2015) Source rock evaluation of selected wells in the North
532 Western Desert, Egypt. Energy Sources Part A 37(20):2151–
533 2162. <https://doi.org/10.1080/15567036.2011.608324>
- 534 El Nady MM, El-Naggar AY (2016) Petroleum geochemistry of crude oils and oil: source rock
535 correlation of some wells in the North Western Desert, Egypt. Arab J Geosci
536 9(13):627. <https://doi.org/10.1007/s12517-016-2617-1>
- 537 Fares FF, Afkareen M, Algomati AE (2026) Investigation of unconventional reservoir of Silurian,
538 Devonian, and Carboniferous source rocks in Ghadames Basin, NW Libya. J Afr Earth Sci
539 240:106118. <https://doi.org/10.1016/j.jafrearsci.2026.106118>
- 540 Ghori KAR, Haines PW (2007) Paleozoic petroleum systems of the Canning Basin, Western Australia:
541 a review. Search and Discovery, Article 10121
- 542 Ghori KAR, Mohammed RA (1996) The application of petroleum generation modelling to the eastern
543 Sirt Basin, Libya. In: Salem MJ, El-Hawat AS, Sbata AM (eds) The Geology of Sirt Basin. Vol II.
544 Elsevier, Amsterdam, pp 529–540.
- 545 Gras R, Thusu B (1998) Trap architecture of the Early Cretaceous Sarir Sandstone in the eastern Sirt
546 Basin, Libya. In: MacGregor DS, Moody RTJ, Clark-Lowes DD (eds) Petroleum Geology of North
547 Africa. Geological Society, London, Special Publications 132:317–334.
548 <https://doi.org/10.1144/GSL.SP.1998.132.01.18>
- 549 Guiraud R, Bosworth W (1997) Senonian basin inversion and rejuvenation of rifting in Africa and
550 Arabia: synthesis and implications to plate-scale tectonics. Tectonophysics 282(1–4):39–82.
551 [https://doi.org/10.1016/S0040-1951\(97\)00215-9](https://doi.org/10.1016/S0040-1951(97)00215-9)
- 552 Gumati YD, Kanes WH, Schamel S (1996) An evaluation of the hydrocarbon potential of the sedimentary
553 basins of Libya. Journal of Petroleum Geology 19(1):95–112. <https://doi.org/10.1111/j.1747-5457.1996.tb00515.x>

555 Gumati YD, Nairn AEM (1991) Tectonic subsidence of the Sirte Basin, Libya. *J Pet Geol* 14(1):93–
556 102. <https://doi.org/10.1111/j.1747-5457.1991.tb00301.x>

557 Gumati YD, Schamel S (1988) Thermal maturation history of the Sirte Basin, Libya. *Journal of*
558 *Petroleum Geology* 11(2):205–218. <https://doi.org/10.1111/j.1747-5457.1988.tb00814.x>

559 Hallash A, Albaghdady A, Aboglila S (2024) Investigation of unconventional reservoirs of the Upper
560 Cretaceous source rocks in the Hameimat Trough, southeast Sirte Basin, Libya. *J Basic Sci* 37(2):145–
561 168. <https://doi.org/10.59743/jbs.v37i2.278>

562 Hallett D (2002) *Petroleum Geology of Libya*. Elsevier, Amsterdam, 503 p.
563 <https://doi.org/10.1016/B978-0-444-51064-7.X5000-3>

564 Hallett D (2016) *Petroleum Geology of Libya*, 2nd edn. Elsevier, Amsterdam, 330 p.
565 <https://doi.org/10.1016/C2014-0-03866-6>

566 Harding TP (1984) Graben hydrocarbon occurrences and structural style. *AAPG Bull* 68(3):333–
567 362. <https://doi.org/10.1306/AD460A21-16F7-11D7-8645000102C1865D>

568 Hassan HS, Kendall CCG (2014) Hydrocarbon provinces of Libya. In: Marlow L, Kendall CGC, Yose
569 LA (eds) *Petroleum Systems of the Tethyan Region*. AAPG Memoir 106. American Association of
570 Petroleum Geologists, Tulsa, Oklahoma, pp 101–141.

571 Hunt JM (1996) *Petroleum Geochemistry and Geology*, 2nd edn. W.H. Freeman and Company, New
572 York, 743 p.

573 Jackson KS, Hawkins PJ, Bennett AJR (1985) Regional facies and depositional environments of the
574 Denison Trough, Queensland. *The APEA Journal* 25(1):143–158.

575 Jarvie DM (2012) Shale resource systems for oil and gas: Part 1 Shale-gas resource systems. In: Breyer
576 JA (ed) *Shale Reservoirs—Giant Resources for the 21st Century*. AAPG Memoir 97. American
577 Association of Petroleum Geologists, Tulsa, Oklahoma, pp 69–87.

578 Jarvie DM, Hill RJ, Ruble TE, Pollastro RM (2007) Unconventional shale-gas systems: The
579 Mississippian Barnett Shale of north-central Texas as one model for thermogenic shale-gas assessment.
580 *AAPG Bulletin* 91(4):475–499. <https://doi.org/10.1306/12190606068>

581 Jawazi AH, Futyan A (1996) The hydrocarbon habitat of the oil and gas fields of North Africa with
582 emphasis on the Sirte Basin. In: Salem MJ, El-Hawat AS, Sbeta AM (eds) *The geology of the Sirte Basin*,
583 vol II. Elsevier, Amsterdam, pp 287–308

584 Jiang S, Huang B, Li J (2017) Oil retention in shale reservoirs. *Marine and Petroleum Geology* 88:812–
585 824.

586 Jones RW (1987) Organic facies. In: Brooks J, Welte DH (eds) *Advances in Petroleum Geochemistry*,
587 Volume 2. Academic Press, London, pp 1–90.

588 Longford FF, Blanc-Valleron MM (1990) Interpreting Rock-Eval pyrolysis data using graphs of
589 pyrolyzable hydrocarbons vs. total organic carbon. *AAPG Bull* 74(6):799–804

590 Murtagh F, Legendre P (2014) Ward’s hierarchical agglomerative clustering method: Which algorithms
591 implement Ward’s criterion? *Journal of Classification* 31(3):274–295. [https://doi.org/10.1007/s00357-](https://doi.org/10.1007/s00357-014-9161-z)
592 [014-9161-z](https://doi.org/10.1007/s00357-014-9161-z)

- 593 Peters KE (1986) Guidelines for evaluating petroleum source rock using programmed pyrolysis. AAPG
594 Bulletin 70(3):318–329. <https://doi.org/10.1306/94885688-1704-11D7-8645000102C1865D>
- 595 Peters KE, Cassa MR (1994) Applied source rock geochemistry. In: Magoon LB, Dow WG (eds) The
596 Petroleum System—From Source to Trap. AAPG Memoir 60. American Association of Petroleum
597 Geologists, Tulsa, Oklahoma, pp 93–120.
- 598 Peters KE, Walters CC, Moldowan JM (2005) The Biomarker Guide: Biomarkers and Isotopes in
599 Petroleum Exploration and Earth History, 2nd edn, Vol 2. Cambridge University Press, Cambridge, 684
600 p.
- 601 Rabbani AR, Kamali MR (2005) Source rock evaluation and petroleum geochemistry, offshore SW Iran.
602 J Pet Geol 28(4):413–428. <https://onlinelibrary.wiley.com/doi/abs/10.1111/j.1747-5457.2005.tb00091.x>
- 603 Roohi M (1996) Source–reservoir relationships in the Sirt Basin, Libya. In: Salem MJ, El-Hawat AS,
604 Sbeta AM (eds) The Geology of Sirt Basin. Vol II. Elsevier, Amsterdam, pp 323–336.
- 605 Rossi ME, Tonna M, Larbash M (1991) Latest Jurassic–Early Cretaceous deposits in the subsurface of
606 the eastern Sirt Basin (Libya): facies and relationships with tectonics and sea-level changes. In: Salem
607 MJ, El-Hawat AS, Sbeta AM (eds) The Geology of Sirt Basin. Vol II. Elsevier, Amsterdam, pp 2211–
608 2225.
- 609 Shaltami OR, Fares FF, Elojaly RB, Aljazwi MS, El Oshebi FM, Errishi H, El-Ehfifi SS, Favalaro RR,
610 Rose O (2021) Organic geochemistry of the Tagrifat Shale in well A1-NC129, Sirt Basin, Libya.
611 International Journal of Multidisciplinary Sciences and Advanced Technology, Special Issue 1:469–474.
- 612 Sikander AH, Basu S (2000) Source-maturation, structural synthesis and volumetric estimates for Upper
613 Cretaceous source rocks, West Central Sirt Basin. Sirte Oil Company, Sirte, Libya.
- 614 Sikander AH, Basu S, Ertug K, Wafa F (2006) Atlas of Petroleum Geology and Geochemistry of Source
615 Rocks and Hydrocarbons in Sirt Basin, Libya. Vol 1. Sirte Oil Company (SOC), Sirte, Libya, Internal
616 Report.
- 617 Tissot BP, Welte DH (1984) Petroleum Formation and Occurrence: A New Approach to Oil and Gas
618 Exploration, 2nd edn. Springer-Verlag, Berlin, 538 p.
- 619 Tyson RV (1995) Sedimentary Organic Matter: Organic Facies and Palynofacies. Chapman and Hall,
620 London, 615 p.
- 621 Waples DW (1985) Geochemistry in Petroleum Exploration. International Human Resources
622 Development Corporation, Boston, 232 p.
- 623 Ziegler PA, Roure F (1999) The Mediterranean petroleum systems: a review. In: Durand B, Jolivet L,
624 Horváth F, Séranne M (eds) The Mediterranean Basins: Tertiary Extension Within the Alpine Orogen.
625 Geological Society, London, Special Publications 156:517–546.

626