Chapter 1
Introduction

1.1 General Overview:

Petroleum geochemistry is the branch of geochemistry that deals with the application of chemical principal in the study of origin, generation, migration, accumulation and alteration of petroleum.

Petroleum is generally considered oil and natural gases having various compounds composed of primarily hydrogen and carbon. They are usually generated from the decomposition and/or thermal maturation of organic matter. The organic matter is deposited from plants and algae. The organic matter is deposited after the death of the plant in sediments, where after the death of the plant in sediments, where after considerable time, heat and pressure the compound in the plants and algae are altered to oil, gas, and kerogen. Kerogen can be thought of as the remaining solid material of the plant. The sediment usually clay and/or calcareous (lime), hardens during the alteration process in the rock.

Source rocks are fine-grained sedimentary rocks containing relatively high concentrations of organic matter deposited in aqueous depositional settings.

The petroleum geochemical techniques used as a tool to satisfied the need in searching for hydrocarbon accumulation and to fulfill the following purposes:

1- Identify source rock and determine the amount, type and maturation level of the organic matter.

2- Evaluate the potential timing of petroleum migration from the source rock.

3- Assess the potential migration pathways.

4- Correlate petroleum found in the reservoirs, lake and surface seeps to find new pools of petroleum.

And the used techniques are:

- Stable isotopes.
- Hydrocarbon analysis of specific organic compounds (biological organic markers).
- Gas chromatography (GC).
- Gas chromatography-mass spectrometry (GC-MS).
- Maturity indicators like vitrinite reflectance, laboratory pyrolysis & analysis and kerogen typing.
- And many more.

1.2 Geological Setting:

1.2.1 Regional Geology:

The Muglad basin is a large rift basin in northern Africa its located within southern Sudan and South Sudan and it cover 120,000 km^2 approximately across the two countries and it's subdivided into northwest and southern sectors. It contains a number of hydrocarbon accumulation in deferent sizes and the largest are Heglig and Unity oilfields (Shull 1988).

The Muglad Basin is part of a trend of Cretaceous sedimentary basins of apparent rift origin, and it extend across north central Africa from the Benue Trough in Nigeria, through Chad and the Central African Republic, into Sudan. The evidence for extension further southeast of this trend has been destroyed by Tertiary uplift associated with recent rifts in Ethiopia and Kenya.

Regional data are limited, but the aeromagnetic and gravity surveys indicate as much as 5 kilometers of sediments Tectonics in the basin is highly complicated by faulting. Seismic data suggest large numbers of tensional faults have affected the overall basin and have defined several sub-basins. Structures within these sub-basins show significant variations in age of formation, complexity and size.

Fig(1.1): Show Muglad Rift Basin

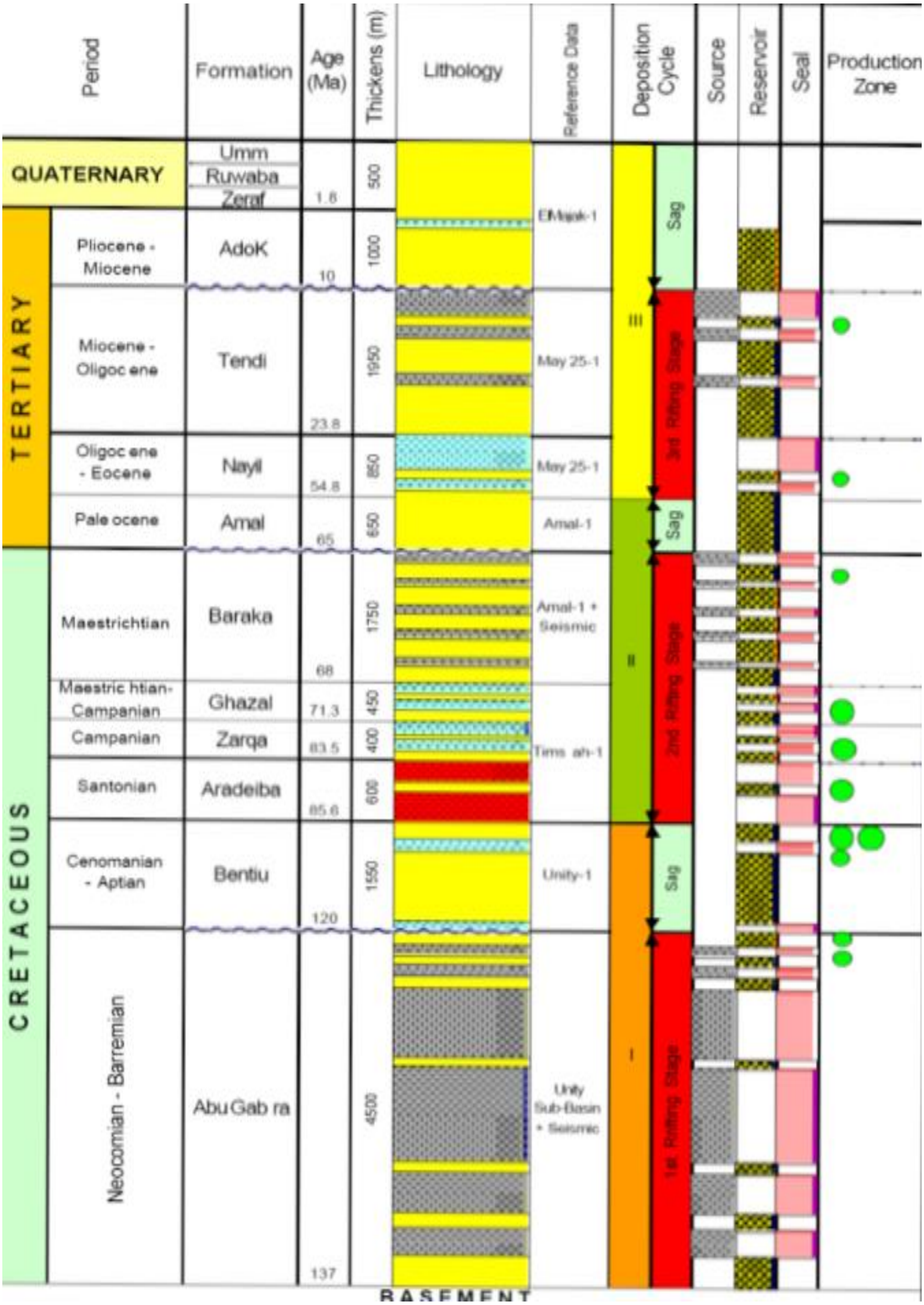
1.2.2 Tectonic Framework:

The development of the Muglad rift basin began during the middle Jurassic and continues until upper Miocene. The rift developed over three cycles and it's linked to processes that operated along the western and eastern continental margins of Africa.

1.2.3 Basin Stratigraphic:

Cyclic sediments are sequences of sedimentary rocks that are characterized by repetitive patterns of different rock types or facies within the sequence. Cyclic sedimentation occurs when the depositional environments change repeatedly. Processes that generate sedimentary cyclicity can be either autocyclic or allocyclic.

The first depositional cycle (Early Cretaceous) consists mainly of sub-oxic organic-rich shale comprising the main lacustrine source beds of the Sharaf and Abu Gabra formations, which are overlain in the sag phase by medium- to coarse-grained sandstones of the Bentiu Formation. The second depositional cycle (Late Cretaceous-Paleocene) is the Darfur Group, comprising fluvial and deltaic claystones at the bottom (Aradeiba Formation) and thin sandstone beds (Zarga and Ghazal formations), thickening toward the top of the section (Baraka Formation) and overlain by the coarser Amal Formation. The thin intercalating sandstones in the Darfur Group are the main reservoirs in the Unity field. The Kordofan Group (Oligocene-late Eocene), which forms the third depositional cycle, consists of the largely shaly Nayil and Tendi formations and culminates in the coarse sandstones of the Adok Formation. The Miocene-Holocene Zeraf Formation unconformable overlies the Adok and probably represents fluvial reworking of these earlier deposits.



Fig(1.2): Show Muglad Basin Stratigraphy

1.3 Scope of Study:

The study focuses on evaluating source rock richness, quality and thermal maturity using rock eval pyrolysis and vitrinite reflectance measurements as well as utilization of GR log to evaluate the organic richness of the Abu Gabra source rock formation in Hamra oilfield, Muglad basin Sudan.

1.4 Literature Review:

Omer adul Abul Gebbayin et.al (2019) Applied geochemical techniques in block 2 & 4 to study a suite of 174 rock cuttings aiming, at identifying and fully characterizing the potential source rock in the basin. They define the organic matter based on the depositional environment and they identify the kerogen types and thermal maturity.

Mohammed Abaker Basher Eldoum et.al (2017) Conduct geochemical study in Azrag area, Muglad basin for 40 samples from three exploration wells using geologic and geochemical techniques and come up with the result that two well was giving oil+gas prone and the other well was giving oil prone according to their HI values and kerogen type.

Michael J. Pearson et.al (2016) Conduct geochemical study in the Fula sub-basin northern Muglad basin for 31 source rock samples from six wells from two oilfields Moga and keyi using geochemical techniques (vitrinite reflectance and source rock analysis SRA) to evaluate the source rock thermal maturity and they produced burial history model and petroleum generation/expulsion model.

Jinqi Qiao et.al (2015) Used well logging data core observation and geochemical techniques combined for 14 well and 113 source rock samples to evaluate the hydrocarbon potentiality in the Sufyan sag which located in the northwest of the Muglad basin and they divided Abu Gabra formation of Sufyan sag into three members and measured HC generation and expulsion in each one**.**

Huang Renchun et.al (2015) calculate TOC from well logging data and build calculation models using improved ΔlgR, bulk density, natural gamma spectroscopy, multi-fitting and volume model methods respectively Field practices demonstrated that the improved ΔlgR and natural gamma spectroscopy methods are poor in accuracy; although the multi-fitting method and bulk density method have relatively high accuracy, the bulk density method is simpler and wider in application. For further verifying its applicability, the bulk density method was applied to calculate the TOC of shale reservoirs in several key wells in the Jiaoshiba shale gas field, Sichuan Basin, and the calculation accuracy was clarified with the measured data of core samples, showing that the coincidence rate of logging-based TOC calculation is up to 90.5%e91.0%.

Yousif M. Makeen et.al (2014) Used geochemical techniques in the Moga oilfield, north-eastern Muglad basin for 33 source rock samples from three wells. They define formation potentiality, identify the kerogen type and produced plots.

1.5 Study Objective:

The main objective of this study is to characterize the source rock in Hamra oilfield area, Muglad basin and to determine the source rock characteristics and the hydrocarbon potentiality.

1.5.1 Specific Objectives:

- Identify source rock richness (Organic Matter Quantity).
- Describing the source rock quality (Kerogen Type/ Potential Hydrocarbon).
- Evaluating the level of thermal maturity of the source rock.

Chapter 2

Methodology

2.1 Rock Eval

38 Sample from two wells (Hamra SE1, Hamra SW2), collected & analyzed. the data were received from CPL (Central Petroleum Laboratory). Which they made the rock eval pyrolysis and measured the vitrinite reflectance using the following procedure:

2.1.1 Rock Eval Pyrolysis and Total Organic Carbon Content (TOC) Determination:

They used Rock eval 6 standard equipment. About 70-100 mg of pulverized sample were placed in the crucible and progressively heated to 650^{o}C under an inert atmosphere (pyrolysis oven).

During the analysis, the hydrocarbons that already present in the sample were volatized at moderate temperature. And the amount was measured and recorded as peak represented S1after that the kerogen present in the sample which generate hydro carbons and hydrocarbons like compounds recoded as S2 and CO_2 and water. The CO_2 that generated recorded as S3. after that at oxidation oven sample were heated up to 850^{o}C where residual carbon was measured and recorded as S4. The percent TOC were not measured directly, but calculated from the formula:

$$TOC\ \% = 0.082\ (S1 + S2) + S4 / 10$$

total organic carbon (TOC) was determined and S1, S2, S3 and Tmax values were obtained.

Parameter S1 (mg HC /g rock) represent the free hydrocarbons in rock samples before the analysis. S2 (mg HC /g rock) values represent the amount of hydrocarbon that formed during thermal pyrolysis of the samples. It can either represent the total hydrocarbon generating potential for immature samples or residual hydrocarbon generating potential for mature and post-mature sample.

The following cut-off values are used to classify the source rock according to S2 values:

Table(2.1): Show S2 Ranges to Indicate OM Richness

S2	Richness
< 2.0	**Poor source rock potential**
2.0 – 5.0	**Fair source rock potential**
> 5.0	**Good source rock potential**

S3 (mg HC /g rock) represent the amount of CO_2 in the rock samples from breaking carboxyl groups and other oxygen containing compounds. TOC represent organic carbon richness of rock samples.

Tmax represent the temperature at which the maximum amount of hydrocarbon degraded from kerogen are generated.

S2/S3 ratio represent a measure of the hydrocarbons amount which can be generated from the rock relative to the amount of organic CO_2 released.

HI represent the hydrocarbons amount that can be generated relative to the amount of organic matter in the source rock.

$$HI = S2 / TOC * 100 \qquad \text{mg HC/g TOC.}$$

OI represent the amount of oxygen relative to the amount of organic carbon present in the samples.

$$OI = S3 / TOC * 100 \qquad \text{mg } CO_2\text{/g TOC.}$$

After the data received from CPL. The laboratory experiment has not been done because there were no available samples beside the devices were broken. (doesn’t worked at that time).

we quick over looked and corrected HI and OI values then it analyzed in specific way using excel to evaluate the following:

2.1.2 Organic Richness:

It’s a measure of the amount of organic matter that can generating hydrocarbon in the sedimentary system.

TOC can indicate source richness but it has it limitation.so S2 vs TOC cross plot were used to identify source rock richness and it provide better result.

2.1.2.1 TOC Limitation:

- High TOC value not necessarily an indicator of shale gas or oil potential.
- High TOC may be associated with rocks containing a woody or oxidized organic matter.
- TOC is sensitive to maturity, it decreased with increasing maturity.
- Sample contamination with oil base mud drilling fluid affect TOC value.
- The S2 vs TOC cross plot were used to indicate whether the samples of different kerogen types were mixed or not.

2.1.3 Organic Matter Quality:

S2/S3 ratio has been used to identify the final output that generated by organic matter as it following:

Table(2.2): Show S2/S3 Ratio to Indicate OM Quality

S2 / S3 ratio	Type of OM
0 - 3	Gas
3 - 5	Gas & oil
> 5	Oil

HI vs Tmax cross plot has been used to identify source rock quality and determine the kerogen type.

2.1.3.1 Type of Organic Matter:

2.1.3.1.1 Type I:

Are characterized by high initial H/C ratios and low initial O/C ratios, this kerogen is rich in lipid-derived material and is commonly, but not always from algal OM in lacustrine (fresh water) environment.

Type I properties:

- H/C atomic ratio > 1.25.
- O/C atomic ratio < 0.15.
- Derived principally from lacustrine algae, deposited in anoxic lake sediment and rarely in marine environments.
- Composed of alginate, amorphous OM, cyanobacteria, fresh water algae, lesser of land plant resin.
- Formed mainly from protein and lipid precursors.
- Has few cyclic or aromatic structures.
- Show great tendency to readily produce liquid hydrocarbons (oil prone) under heating.

2.1.3.1.2 Type II:

Are characterized by intermediate initial H/C ratios and intermediate initial O/C ratios, this kerogen is principally derived from marine organic materials, which are deposited in reducing sedimentary environment.

The sulfur content of type II kerogen is generally higher than in other kerogen types and sulfur is found in substantial amounts in the associated bitumen.

rich in lipid-derived material and is commonly, but not always from algal OM in lacustrine (fresh water) environment.

Type II properties:

- H/C atomic ratio < 1.25.

- O/C atomic ratio 0.03 - 0.18.
- Derived principally from marine plankton and algae.
- Tend to yields less oil than type I.
- Produces a mixture oil and gas under heating.

2.1.3.1.3 Type II-S:

Similar to type II but with high sulfur content.

2.1.3.1.4 Type III:

Are characterized by low initial H/C ratios and high initial O/C ratios, this kerogen is derived from terrestrial plant matter specially from cellulose, lignin, terpenes and phenols. coal is an example for this type of kerogen.

Type III properties:

- H/C atomic ratio < 1.
- O/C atomic ratio 0.03 - 0.3.
- Derived principally from terrestrial plants (land).
- Has low hydrogen content because of abundant aromatic carbon structures.
- Tend to produce gas under heating.

2.1.3.1.5 Type IV:

Comprises mostly inert organic matter in the form of polycyclic aromatic hydrocarbon. And it has no potentiality to produce hydrocarbon.

2.1.4 Thermal Maturity:

It's a measure of the degree to which the sediment has been altered by the effect of time and temperature combined.

Tmax has been used to determine source rock maturity particularly at the top of oil window.

Table(2.3): Show Tmax ranges to Indicate Level of Thermal Maturity

Level of maturity	Tmax
Immature	**<435**
Mature	**435-455**
Postmature	**>455**

HI vs Tmax cross plot has been used to identify the level of thermal maturity.

2.2 Vitrinite Reflectance:

Is a measure of the percentage of incident light reflected from the surface of vitrinite particles in sedimentary rocks.

The samples were crushed to about 1mm diameter and mounted on resin blocks. The harden block were ground using silicon carbide paper and polished with diamond paste of various grades. after that the vitrinite measurements were made using J&M MPM 200 photometer microscope under oil immersion at wavelength of 546 nm. Prior to the analysis the photometer was calibrated using (saphir) standard of 0.591% reflectance and checked by (gadolinium-galium-granat) standard of 1.718% reflectance. VRo values has been used to identify thermal maturity

Table(2.4): Show VRo ranges to Indicate Level of Thermal Maturity

VRo(%)	Level of thermal maturity
<0.5	Immature
0.5-1.3	Mature
>1.3	Postmature

Depth vs Ro plot has been used to indicate changes in vitrinite properties with depth.

2.3 TOC Calculation from Well Logging Data:

The TOC vs GR cross plot were used to create equation for determining the TOC from GR log without taking sampling in the Abu Gabra source rock formation in Hamra oilfield, Muglad basin Sudan.

Gama ray log values obtained from the las file corresponding to the samples depths then were cross plotted with the laboratory measured TOC. The equation of the trendline was then applied to obtain the calculated TOC for selected depths in the Abu Gabra formation within Hamra oilfield.

Finally, a plot of measured TOC and calculated TOC against depth was made to correlate the values.

Chapter 3

Result and Discussion

3.1 Organic Matter Richness:

Organic matter richness of organic matter from Abu Gabra Formation in Hamra SE-1 and Hamra SW2 shales were evaluated using pyrolysis S_2 yield, TOC content.

The Hamra SE-1 shales have relatively fair to good TOC content (0.19 -2.13wt %), while Hamra SW-2 shales have relatively fair to good TOC content (0.15 - 1.63wt %) hence, the proportion of organic carbon content of Hamra SE-1 and Hamra SW-2 shales are modest enough to classify them as possessing fair to good source rock generative potential.

In the analyzed samples of Hamra SE-1 shales, the hydrocarbon (S_2) yield ranges from 0.08 to 4.90 mg hydrocarbon (HC) / g rock for all lithologies (Table 3.1) and the pyrolysis S_2 yield for Hamra SW-2 shales ranges from 0.04 to 4 mg HC/g rock (Table 3.2).

Table(3.1): Show Hamra SE-1 Data

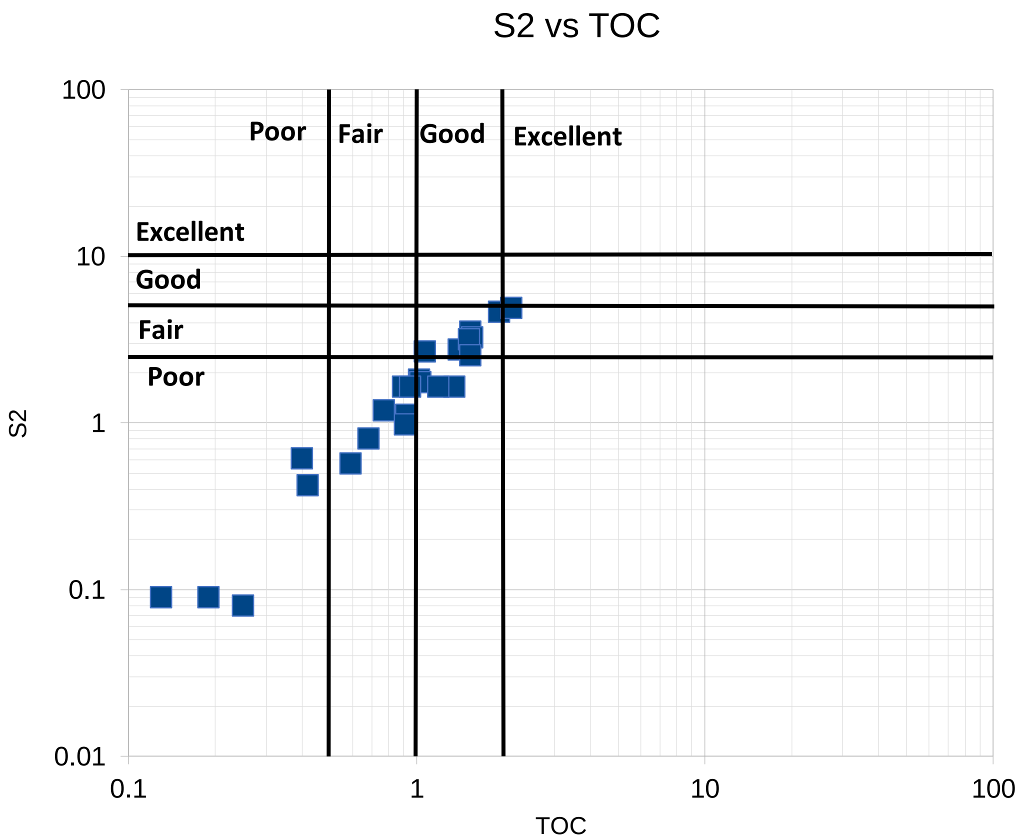
No	Depth	TOC	S1	S2	S3	S1+S2	Tmax	OI	HI	S2/S3
1	3185	0.25	0.04	0.08	0.71	0.12	411	284	32	0.11
2	3260	0.19	0.03	0.09	0.58	0.12	429	305	47	0.16
3	3310	1.02	0.37	1.82	0.83	2.19	450	81	178	2.19
4	3320	1.40	0.37	2.75	0.79	3.12	444	56	196	3.48
5	3345	1.03	0.21	1.75	0.92	1.96	447	89	170	1.90
6	3355	1.54	0.28	3.51	0.87	3.79	449	56	228	4.03
7	3365	0.59	0.09	0.57	1.13	0.66	456	192	97	0.50
8	3375	0.90	0.19	1.65	0.93	1.84	452	103	183	1.77
9	3390	0.42	0.05	0.42	0.99	0.47	457	236	100	0.42
10	3455	1.56	0.72	3.25	0.76	3.97	448	49	208	4.28
11	3460	1.93	0.64	4.65	0.74	5.29	444	38	241	6.28
12	3480	2.13	1.07	4.90	0.69	5.97	436	32	230	7.10
13	3495	1.52	0.99	3.17	0.82	4.16	444	54	209	3.87
14	3510	0.68	0.17	0.80	0.69	0.97	461	101	118	1.16
15	3530	0.92	0.24	1.11	0.69	1.35	461	75	121	1.61
16	3550	1.35	0.36	1.65	0.70	2.01	459	52	122	2.36
17	3565	0.91	0.23	0.98	0.70	1.21	461	77	108	1.40
18	3580	1.54	0.59	2.53	0.84	3.12	451	55	164	3.01
19	3610	0.95	0.27	1.64	0.66	1.91	452	69	173	2.48
20	3615	1.07	0.64	2.67	0.78	3.31	422	73	250	3.42
21	3635	0.77	0.16	1.19	0.80	1.35	453	104	155	1.49
22	3645	0.13	0.02	0.09	0.65	0.11	452	500	69	0.14
23	3660	0.40	0.13	0.61	0.61	0.74	451	153	153	1.00
24	3735	1.19	0.48	1.65	0.73	2.13	453	61	139	2.26

Table(3.2): Show Hamra SW-2 Data

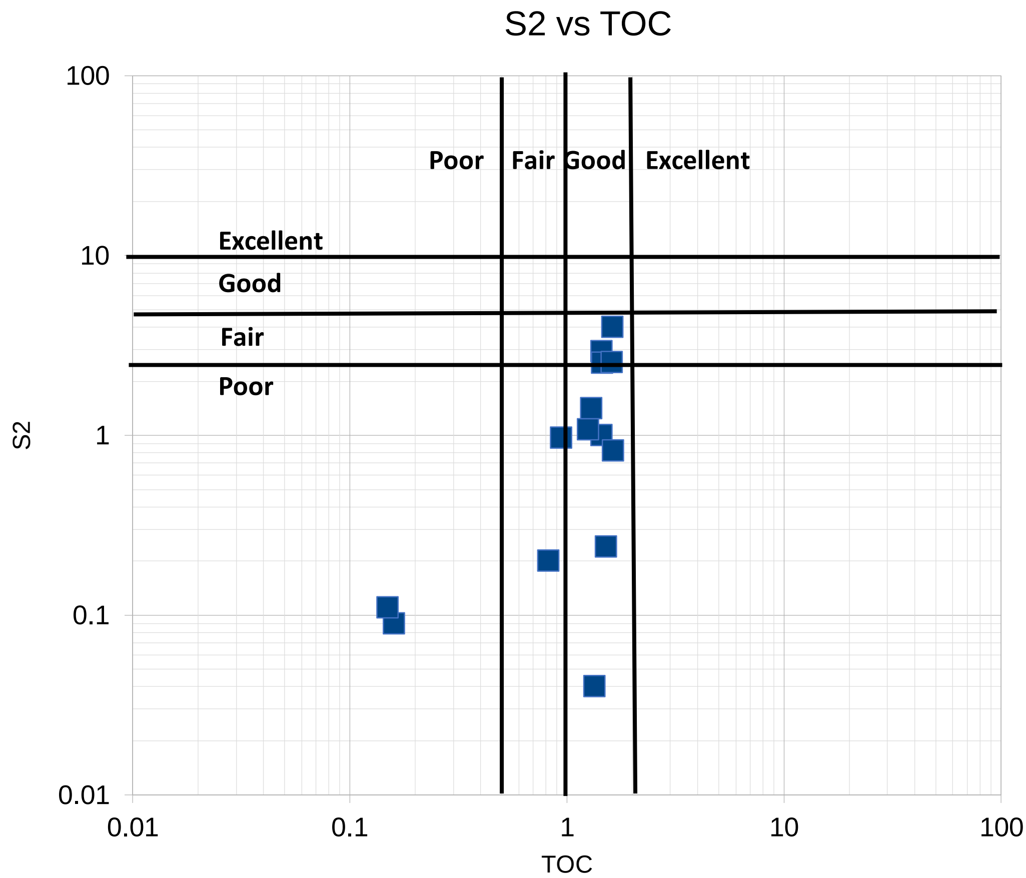
NO	Depth	TOC	S1	S2	S3	S1+S2	Tmax	OI	HI	S2/S3
1	2850	0.16	0.01	0.09	1.21	0.10	443	756.25	56.25	0.07
2	3000	0.15	0.02	0.11	1.28	0.13	442	853.33	73.33	0.09
3	3170	1.45	0.53	2.94	0.37	3.47	453	25.52	202.76	7.95
4	3285	1.45	0.33	1.00	0.46	1.33	450	31.72	68.97	2.17
5	3300	0.94	0.23	0.97	0.63	1.20	447	67.02	103.19	1.54
6	3330	1.25	0.47	1.08	0.63	1.55	424	50.40	86.40	1.71
7	3430	1.62	0.85	4.00	0.54	4.85	441	33.33	246.91	7.41
8	3530	1.46	0.40	2.52	0.80	2.92	458	54.79	172.60	3.15
9	3535	1.61	0.44	2.55	0.53	2.99	460	32.92	158.39	4.81
10	3550	1.30	0.29	1.41	0.54	1.70	467	41.54	108.46	2.61
11	3635	1.63	2.60	0.82	0.52	3.42	444	31.90	50.31	1.58
12	3660	1.52	0.64	0.24	1.34	0.88	443	88.16	15.79	0.18
13	3670	0.82	0.56	0.20	1.08	0.76	444	131.71	24.39	0.19
14	3780	1.34	0.26	0.04	1.81	0.30	441	135.07	2.99	0.02

The hydrocarbon yields (S2) are indicating that Hamra SE-1 shale sediments have poor to good source rock, while hydrocarbon yields(S2) for Hamra SW-2 are indicating poor to good source rock.

Hamra SE-1 and SW-2 Samples are frustrating source rock for hydrocarbon generation as reflected by the modest S2 and modest TOC (wt%) content (fig 3.1 & Fig 3.2).



Fig(3.1): Hamra SE-1samples plot shows the organic matter richness.



Fig(3.2): Hamra SW-2 samples plot shows the organic matter richness.

3.2 Organic Matter Quality:

To interpret the organic data in terms of paleoenvironmental changes and quality, information about the composition which discriminates between marine and terrigenous sources is necessary.

Kerogen typing is also considered to produce different types of hydrocarbons. Generally, type I and II kerogens commonly derived from lacustrine and marine source rocks are capable of generating liquid hydrocarbons. Type III kerogen is mostly composed of woody materials and gas prone, and type IV is composed primarily of inert materials and has no potential of generating hydrocarbons. Based on the pyrolysis data, the kerogen classification diagrams were constructed using hydrogen index (HI) versus Tmax.

Hamra SE-1 pyrolysis data (HI against Tmax) (Fig 3.3) indicated that the analyzed Abu Gabra Formation samples generally plot in the mature zone of mixed type I–III kerogens grading to type III kerogen (Fig 3.3). This corresponds to their HI values in the range of 32–250 mg HC/g TOC (Table 3.1). Most samples are plotted in the type I-III kerogens field in this diagram. while Hamra SW-2 data (fig 3.5) indicated that the analyzed Abu Gabra formation samples generally plotted in mature zone of mixed type I–III kerogens grading to type III kerogen (Fig 3.5). This corresponds to their HI values in the range of 2.99–246.91 mg HC/g TOC (Table 3.2). Most samples are plotted in the type I-III kerogens field in this diagram, and some are plotted in type III kerogen field.

These suggest that the Abu Gabra Formation sediments of Hamra SE-1 can be expected to generate mainly gas with limited capability to generate liquid hydrocarbons while Hamra SW-2 cannot act promising relatively.

3.3 Thermal Maturity of Organic Matter:

Thermal maturation of organic matter causes distinct changes in the physical and chemical characteristics of the organic matter to form petroleum hydrocarbons.

A number of data types were used to assess the level of thermal maturity of organic matter in Abu Gabra shale sediments. The maturity data include mean vitrinite reflectance (%R_o), T_{max} values.

Hamra SE-1 maturity plot (HI vs Tmax) (Fig 3.3), which suggested that the Abu Gabra samples are thermally mature. This is consistent with vitrinite reflectance and T_{max} values shale sediments (Table 3.3) Tmax value of range (411 to 457) indicate maturity of the source rock of Hama

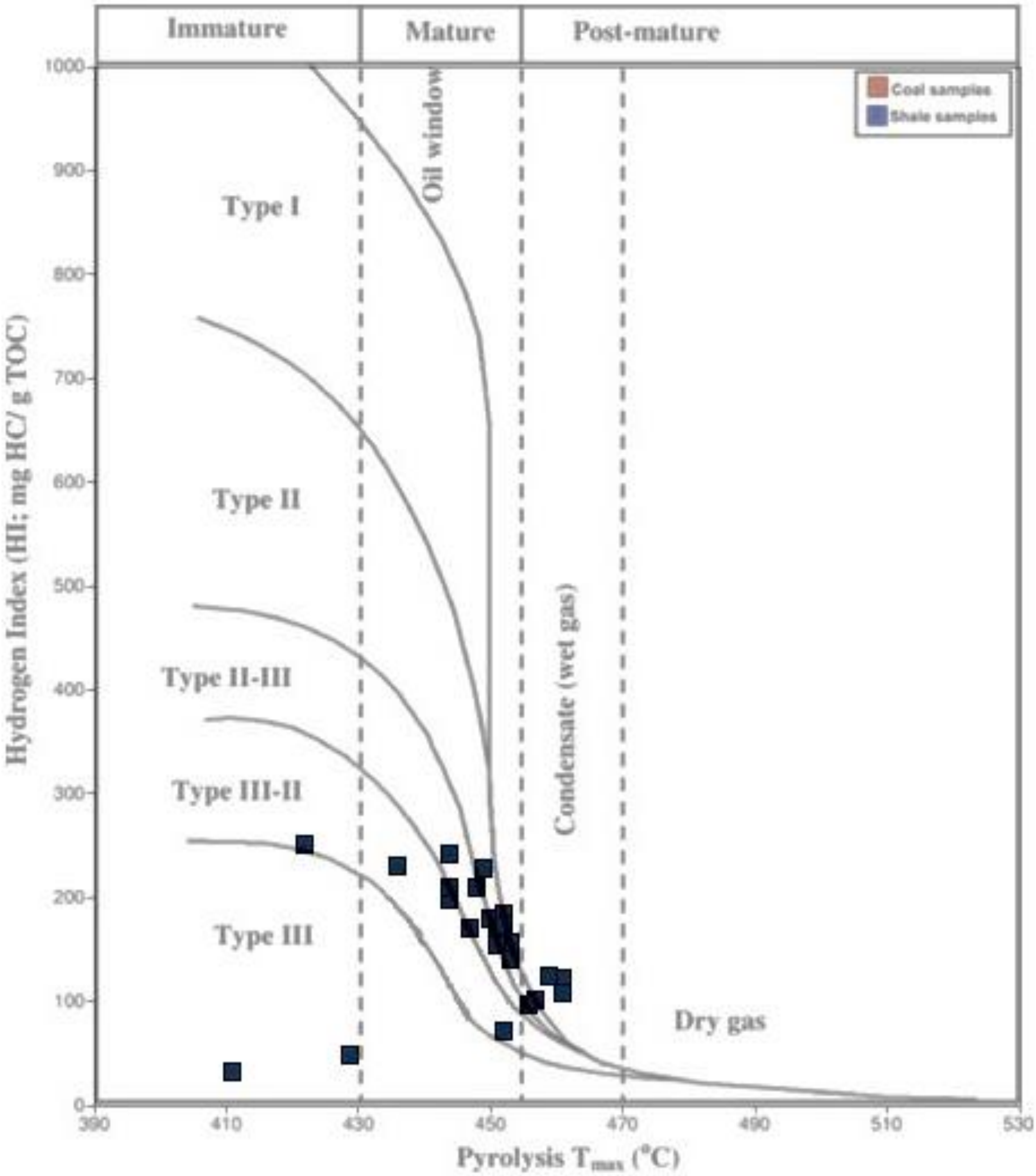
SE-1 (Table 3.1), while Tmax value of range (424 to 467) indicate mature source rock of Hamra SW-2 (Table 3.2). The mean reflectance of vitrinite particles of Hamra SE-1ranges from 0.62 to 0.95 % (Table 3.4), and ranges from 0.62 to 0.94 in Hamra SW-2 particles. Showing that the samples are thermal mature and maturity increases with depth increase (Fig 3.4 & Fig 3.6), which agreement with Tmax value.

Table(3.3): Show Hamra SE-1 VRo Data

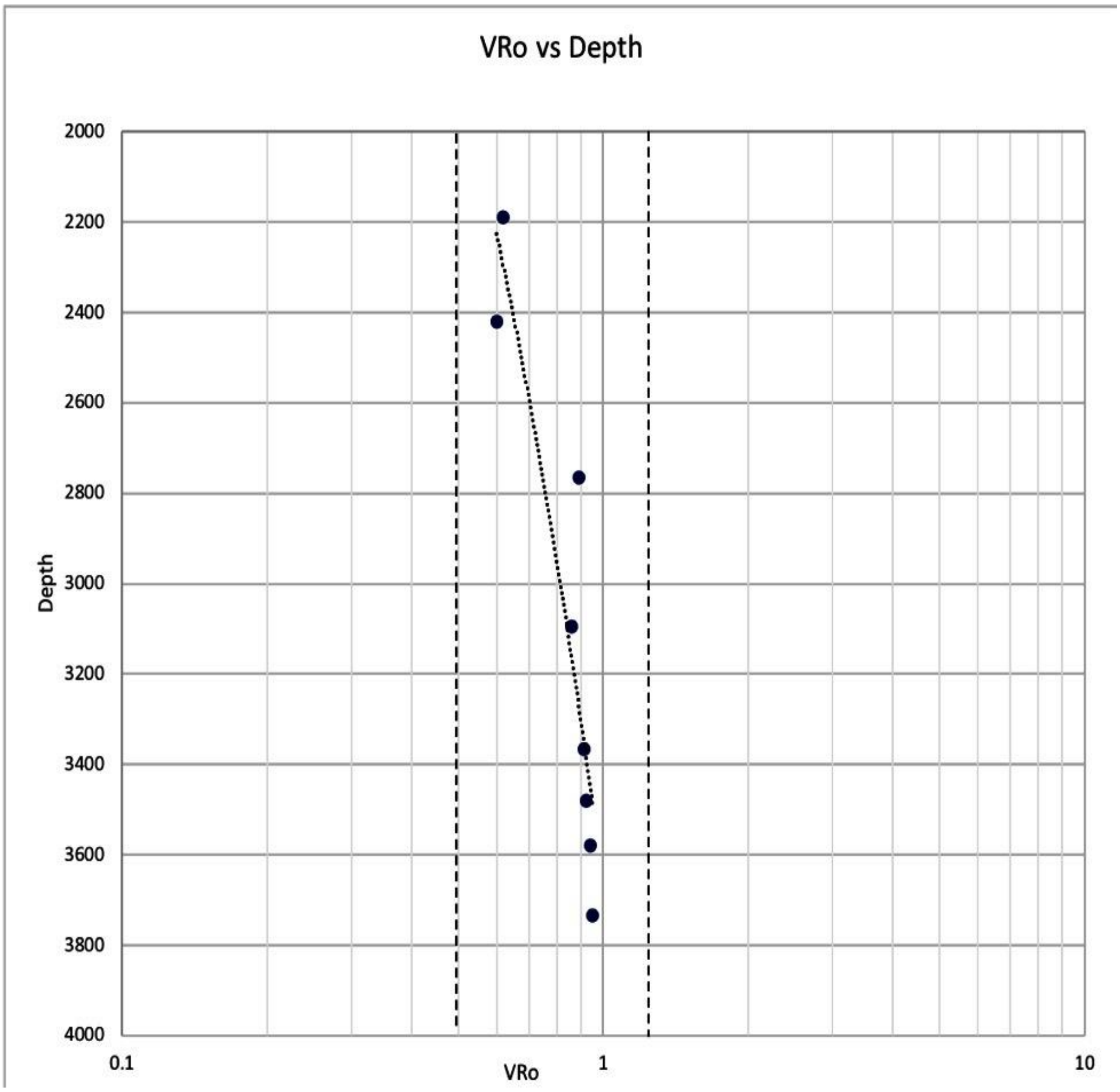
		VRo. Readings				
No.	Sample Depth (m)	Min (%)	Max (%)	Mean (%)	No. of readings	Note
1	1915	/	/	/	/	ND
2	2190	0.53	0.70	0.62	6	/
3	2420	0.47	0.75	0.60	10	/
4	2765	0.89	0.89	0.89	1	/
5	2915	/	/	/	/	ND
6	3095	0.74	0.99	0.86	19	/
7	3365	0.77	1.01	0.91	19	/
8	3480	0.92	0.92	0.92	1	/
9	3580	0.79	1.09	0.94	14	/
10	3735	0.84	1.10	0.95	12	/

Table(3.4): Show Hamra SW-2 VRo Data

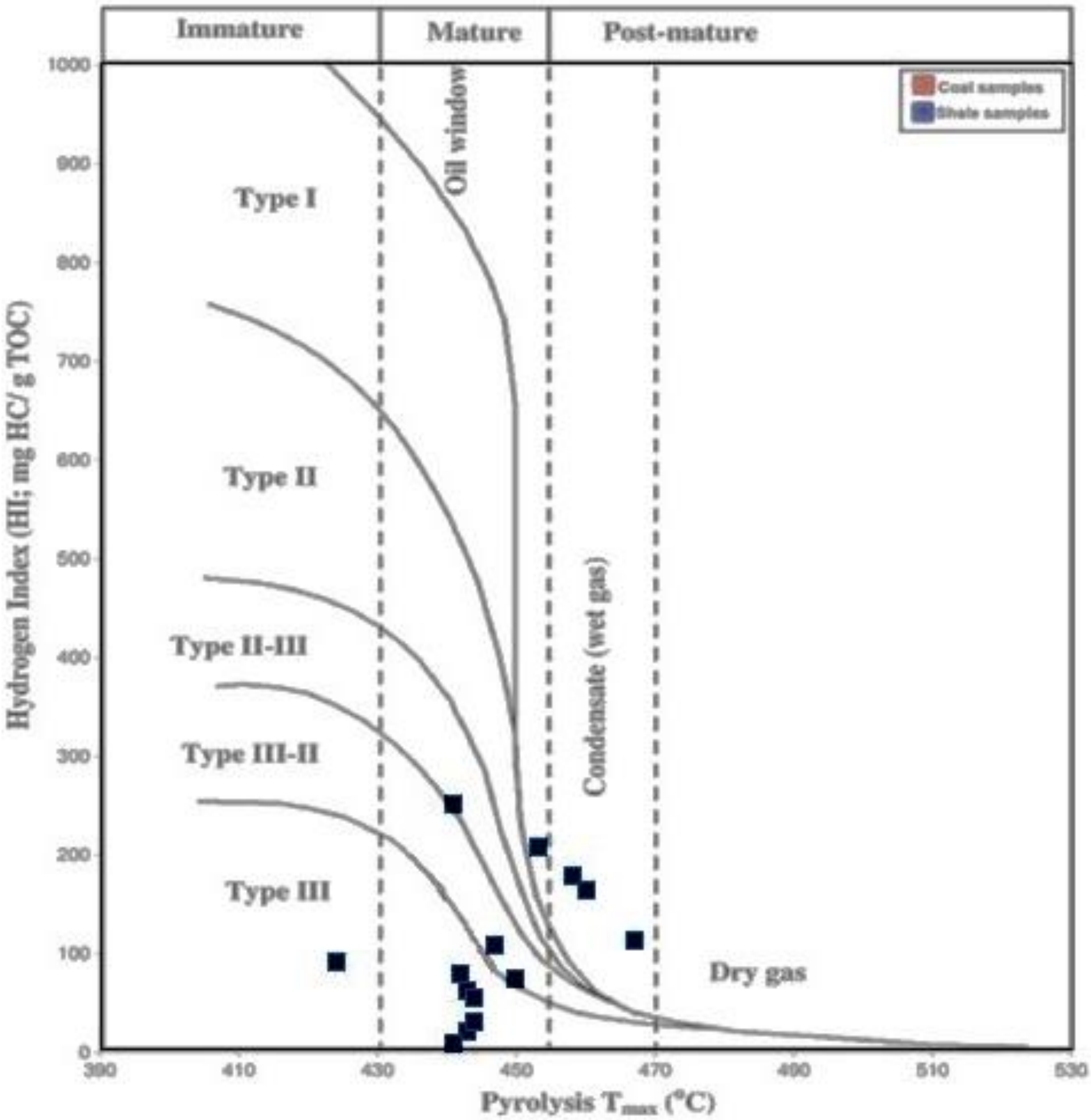
		VRo. Readings				
No.	Sample Depth (m)	Min (%)	Max (%)	Mean (%)	No. of readings	Note
1	720	/	/	/	/	N/A
2	830	/	/	/	/	N/A
3	1050	0.68	0.87	0.77	6	/
4	1175	0.62	0.62	0.62	1	/
5	1900	/	/	/	/	N/A
6	2375	0.52	0.79	0.65	10	/
7	2745	0.72	0.9	0.82	11	/
8	3000	0.81	0.95	0.88	5	/
9	3170	0.72	1.03	0.88	20	/
10	3330	/	/	/	/	N/A
11	3530	0.80	1.05	0.94	12	/
12	3780	/	/	/	/	N/A



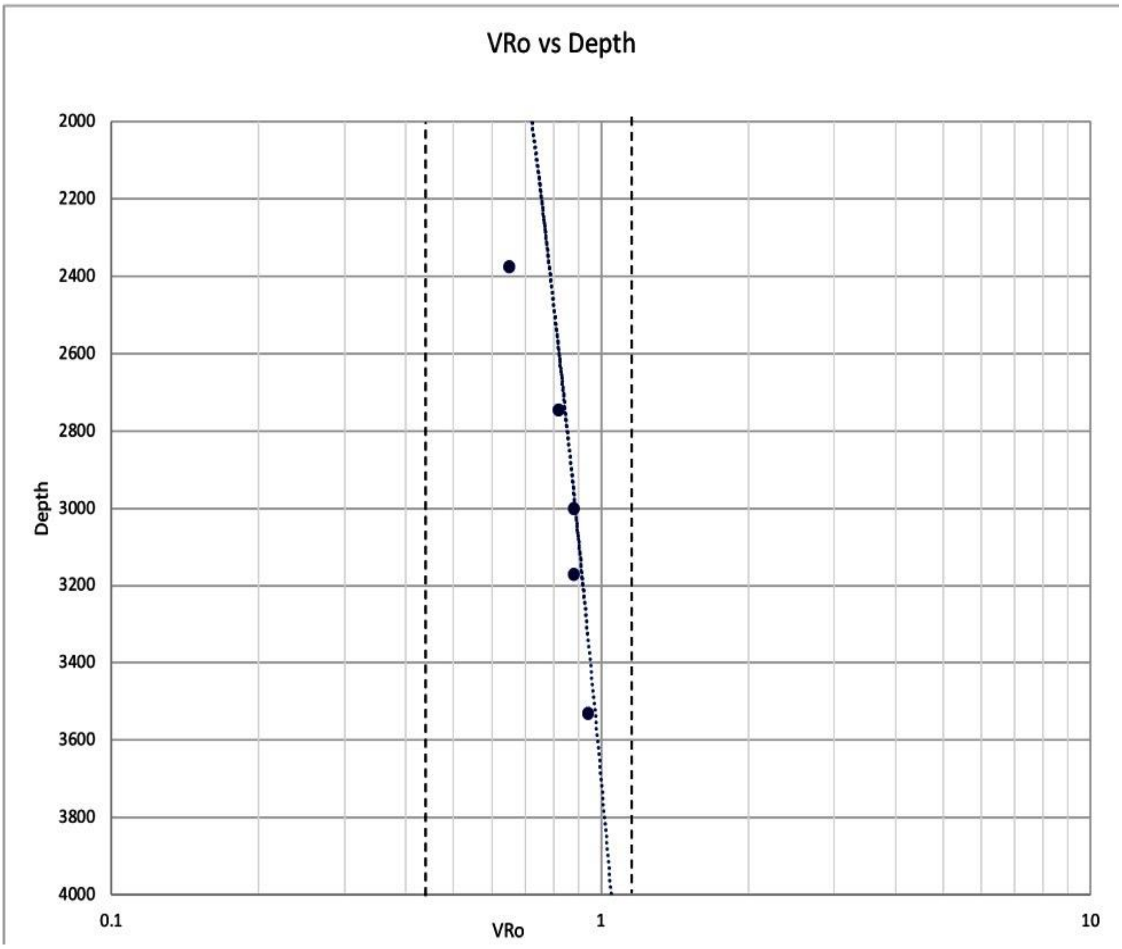
Fig(3.3): HI vs Tmax crossplot show thermal maturity of Hamra SE-1.



Fig(3.4): Depth vs VRo cross plot vitrinite reflectance confirm thermal maturity and show relationship of VRo and depth for Hamra SE-1.



Fig(3.5): HI vs Tmax cross plot show thermal maturity of Hamra SW-2.



Fig(3.6): Depth vs VRo cross plot vitrinite reflectance confirm thermal maturity and show relationship of VRo and depth for Hamra SW-2.

3.4 TOC Calculation from Well Logging Data:

TOC vs Gamma ray cross plot for Abu Gabra formation in Hamra oilfield, Muglad basin Sudan (Fig 3.7) was made from the depths where there is core sample (Table 3.5 & Table 3.6) to produce the trend line equation to calculate TOC at any depth where there is no core samples (Table 3.7, Table 3.8):

$$y = 0.009X + 0.2363$$

Where:

y represents Calculated TOC.

X represents GR log.

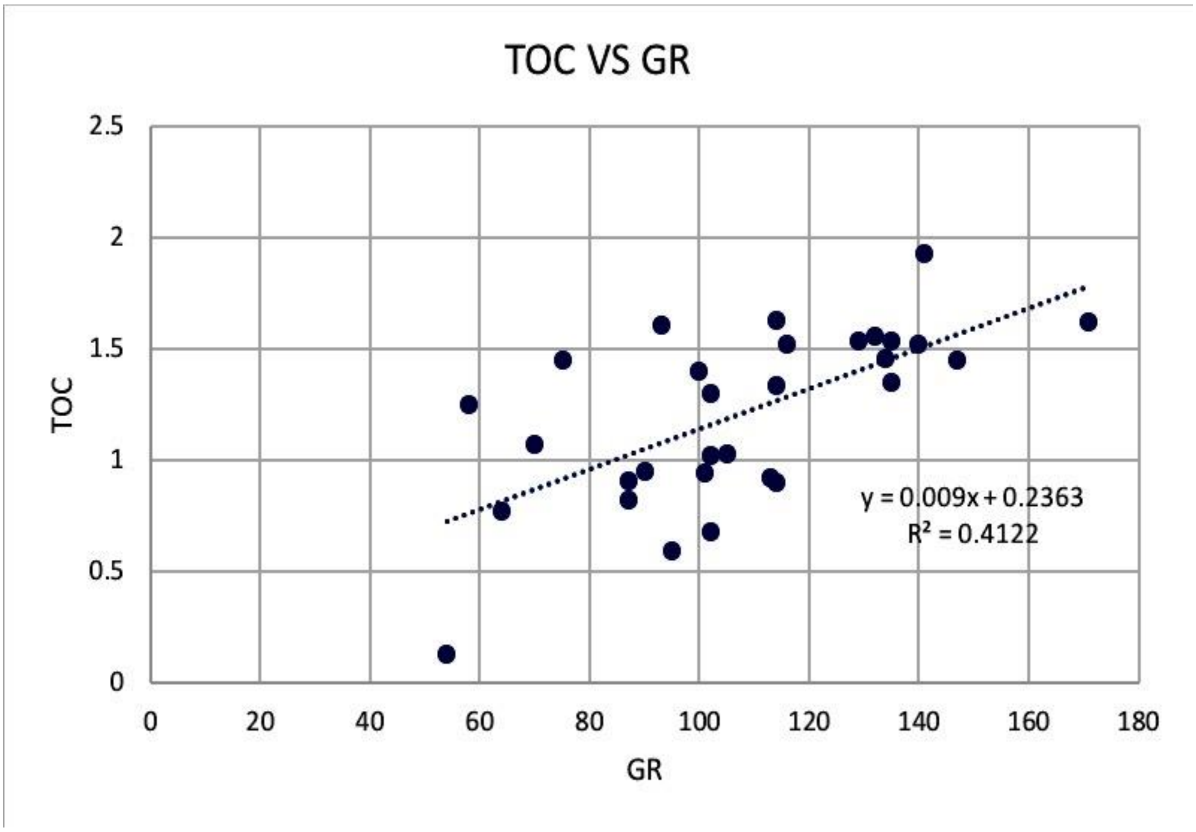
Table(3.5): Show TOC and Calculated TOC Against Depth in Hamra SE-1

No	Depth	GR	TOC	TOC Cal
1	3310	102	1.02	1.15
2	3320	100	1.40	1.14
3	3345	105	1.03	1.18
4	3355	129	1.54	1.40
5	3365	95	0.59	1.09
6	3375	114	0.90	1.26
7	3455	132	1.56	1.42
8	3460	141	1.93	1.51
9	3495	140	1.52	1.50
10	3510	102	0.68	1.15
11	3530	113	0.92	1.25
12	3550	135	1.35	1.45
13	3565	87	0.91	1.02
14	3580	135	1.54	1.45
15	3610	90	0.95	1.05
16	3615	70	1.07	0.87
17	3635	64	0.77	0.81
18	3645	54	0.13	0.72

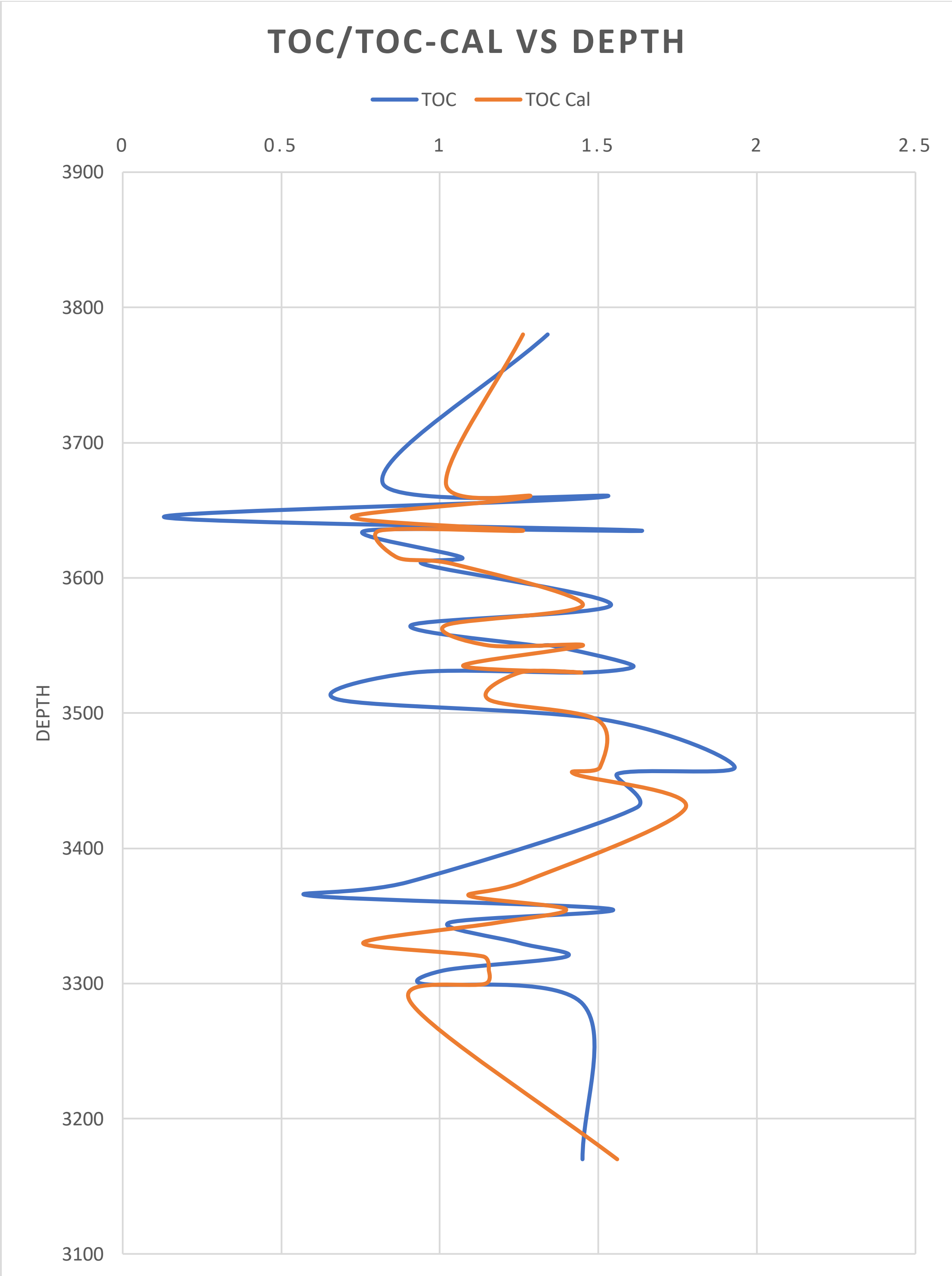
Table(3.6): Show TOC and Calculated TOC Against Depth in Hamra SW-2

No	Depth	GR	TOC	TOC Cal
19	3170	147	1.45	1.56
20	3285	75	1.45	0.91
21	3300	101	0.94	1.15
22	3330	58	1.25	0.76
23	3430	171	1.62	1.78
24	3530	134	1.46	1.44
25	3535	93	1.61	1.07
26	3550	102	1.3	1.15
27	3635	114	1.63	1.26
28	3660	116	1.52	1.28
29	3670	87	0.82	1.02
30	3780	114	1.34	1.26

The error R^2 is quite small and acceptable equal 0.4122 the equation used to determine TOC values in various depths in Abu Gabra formation and cross plot between TOC and calculated TOC with depth was made (Fig 3.8).



Fig(3.7) TOC vs GR cross plot form Abu Gabra formation in Hamra oilfield.



Fig(3.8) TOC/TOC-calc vs depth.

calculated TOC at depths where there are no core samples, are shown in the following tables:

Table(3.7): Show Calculated TOC at Depths Where There are No Core Samples in Hamra SE-1

HAMRA SE-1			
No	**Depth**	**GR**	**TOC Cal**
1	**2290**	**83**	**0.98**
2	**3000**	**82**	**0.97**
3	**3125**	**102**	**1.15**
4	**3150**	**95**	**1.09**
5	**3160**	**78**	**0.94**
6	**3175**	**94**	**1.08**
7	**3700**	**87**	**1.02**
8	**3715**	**72**	**0.88**
9	**3725**	**30**	**0.51**
10	**3740**	**30**	**0.51**

Table(3.8): Show Calculated TOC at Depths Where There are No Core Samples in Hamra SW-2

HAMRA SW-2			
No	**Depth**	**GR**	**TOC Cal**
1	**2790**	**95**	**1.09**
2	**2800**	**118**	**1.30**
3	**2815**	**93**	**1.07**
4	**2825**	**88**	**1.03**
5	**2840**	**63**	**0.80**
6	**2680**	**74**	**0.90**
7	**2690**	**52**	**0.70**
8	**3700**	**166**	**1.73**
9	**3785**	**114**	**1.26**
10	**3799**	**144**	**1.53**

Chapter 4

Conclusion and Recommendations

4.1 Conclusion

Based on TOC, S1, S2, S3 and T_{max} values parameters obtained from Rock–Eval pyrolysis of the shales of the Abu Gabra formations in Hamra oilfield have the same type of organic matter. The organic matter consists of mixed type I/III kerogen formed under reducing lacustrine environment and considered as gas and oil/gas prone and has already crossed the onset of the mature stage of catagenesis. Abu Gabra formation in Hamra SE-1 and Hamra SW-2 contains fair to good source potential rocks. The organic matters of the shales of the Abu Gabra formation in Hamra oilfield are variable in maturity level from initial stage to maturation stage of catagenesis. The shales of this formation could be considered as gas and oil/gas prone rocks.

Based on vitrinite reflectance (0.62-0.95%Ro) and T_{max} values (411-467 C) indicate that the most Abu Gabra sediments samples have entered oil generation window.

TOC values calculated from GR log measurements can provide an initial guess of the source rock richness in the areas where core measurements are not available.

4.2 Recommendations:

According to the results of this study, the following can be recommended for further studies:

1. Undertaking Gas Chromatography analysis on the samples in order to have an idea about the exact composition of the source rock kerogen, and therefore confirming the source characteristics.
2. Obtaining samples from the bottom of Abu Gabra source rock formations to either prove or otherwise disprove the presence of another source rock which might be the one responsible for the expulsion of the hydrocarbons in the field.
3. Analyzing the oil samples from the field to establish a cross-correlation with existing source rock.

4.2 References:

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