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Geochemical and Petrographic Evaluation of the Lower Cretaceous Abu Gabra Organic-Rich Shale in the Muglad Basin, Sudan, with Evidence of Suppression of Thermal Maturity

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Abstract
The Lower Cretaceous Abu Gabra Formation (Albian-Aptian) is major source rocks that widespread in the region consisting of mainly rich shale and claystone with minor sandstone. In this study, a total of 77 cuttings samples of Abu Gabra rich shale and claystone sediments from five boreholes in the Fula sub-basin were subjected to Source Rock Analyzer (SRA), Total Organic Carbon (TOC) analysis, Pyrolysis–Gas Chromatography (Py-GC), conventional Soxhlet extraction procedure as well as vitrinite reflectance measurements. This was done to determine the organic matter quantity, quality (kerogen Type) and thermal maturity with evidence of suppression of thermal maturity within the study area. Based on these analyses, the hydrocarbon generation potential as indicated by the TOC content in the formation shows significant variation in organic matter quantity and ranges between 'good, very good to excellent' (average: 3.04 wt %). Similarly, the hydrocarbon genetic potential ranging from good to very good (with an average of 18.8 mg/g for S1+S2) and good to excellent hydrocarbon (saturated and aromatics) yields (600<HC ppm>2400) were observed for the studied Fula samples. Moreover, the analyzed sediments have high hydrogen index (HI) values (197 to 837 mg HC/g rock) which is consistent with oil-prone Type I and Type II kerogens. This is further supported by the abundant liptinitic materials (i.e., lipid-rich structured algae, spores and pollen, cuticles, and resins). However, there is possibility that the thermal maturity parameter such as vitrinite reflectance (VR) and T_{max} in the studied area might be suppressed especially for the sequences that are liptinite rich and possibly contains perhydrous organic matter. Despite this, Pyrolysis T_{max} indicates that most of the analyzed Abu Gabra sediments are consistent with the HCs being indigenous to a mature source rock. This is supported by mean vitrinite reflectance (%Ro) values that range from 0.58 to 0.76% Ro, which suggest these samples have entered early mature oil window. However, a high thermal maturity of >0.8% Ro is expected for the area as the hydrocarbon exploration in the area shows evidence that it has entered the gas window.

Keywords*: Source rock evaluation; Oil-generation potential; Thermal maturity suppression; Abu Gabra sediments; Fula Sub-Basin, Muglad Basin, Sudan.*

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I. Introduction

The Lower Cretaceous Abu Gabra Formation (Albian-Aptian) is a major source rocks within the Sudanese Fula sub-basin which lies in the northeastern part of the Muglad Basin and covers an area of about 3600 km^2 (Makeen et al., 2015 & 2016). A number of hydrocarbon accumulations of various sizes have been discovered in the sub-basin containing Cretaceous and Tertiary sediments. The general petroleum geology of the Fula sub-basin was reported by Lirong et al., 2013, while other aspects of the Muglad Basin were initially reported three decades ago. Petroleum exploration and development was reviewed by Schull (1988). The author identified organic-rich shales of the Lower Cretaceous Abu Gabra Formation within the Muglad Basin as a good to excellent oil-prone source rocks (Types I and II). This was further supported by Dou et al., 2002 and Tong et al., 2004 based on assessment of bulk parameters and biomarker characteristics of oils and source rock extracts showing that the Abu Gabra Formation is the major source rocks within the Muglad Basin. Oil production of Heglig (at the border between South Sudan and Sudan) and Unity (in Unity State, South Sudan) oilfields was up to 300,000 barrels per day in 2010 (Lirong et al., 2013; Mohamed Yahya, personal communication).

The Fula sub-basin is a fault-bounded depression situated in the NE of the Muglad Basin, Sudan, and covers an area of about 3560 km^2. Eleven oilfields and oil-bearing structures which have been discovered in the sub-basin are Fula, Fula North, Fula Northeast, Fula South, Fula West, Moga, Keyi, Jake, Jake South, Bara and Arad (Lirong et al., 2013; Mohamed Yahya, personal communication).

Petroleum exploration in the sub-basin began in 1970s and with the drilling of the Baleela-1 well in 1985 when very low oil/gas shows was recorded; little further exploration work was undertaken during subsequent decades (Lirong et al., 2013). However a number of explorations programme including 2000 km of 2D seismic, 1334 km^2 of 3D seismic and the drilling of 68 exploration wells has been carried out since 1996. Thus, several hydrocarbon accumulations of various sizes have been discovered in the sub-basin up to the tune of about 60,000 barrels per day in 2011 (Lirong et al., 2013; Mohamed Yahya, personal communication).

This study seeks to employ geochemical and petrographic tools to evaluate source-rock of the Lower Cretaceous Abu Gabra organic-rich shale in the Muglad Basin, Sudan, with evidence of suppression of Thermal Maturity. The petrographic analyses include vitrinite reflectance and kerogen typing (on whole rock), whereas the organic geochemical analyses applied were Source Rock Analyzer (SRA), Total Organic Carbon (TOC), Pyrolysis–Gas Chromatography (PY-GC), extractable organic matter (EOM) and sulfur (TS) contents. These analyses were carried out to establish the essential properties for source rock evaluation such as quantity, quality, and thermal maturity of the organic matter as classified by Tissot and Welte (1984) and Peters and Cassa (1994).

In terms of hydrocarbon generation, in addition to the genetic potential and hydrocarbon yield, cross plots of TOC (%) versus S2 (mg HC/g rock), EOM (ppm) versus TOC (%), and TOC (%) versus hydrocarbons (ppm) were employed to describe source rock-richness. Organic matter types are classified with reference to the main types of Tissot et al. (1974), based on T_{max} (^oC) versus HI, and HI versus OI cross plots. From the petrographic studies, inferences were made based on the liptinite macerals on the possibility of suppression of the thermal maturity parameters. The distribution and significant of these parameters in the currently studied samples are emphasized in the discussed in sections.

II. Geologic setting

The Cretaceous rift Muglad basin is a north-west to south-east trending basin covering about 200 km wide and more than 800 km long in Sudan (Schull, 1988; McHargue et al., 1992; Makeen et al., 2015 & 2016) (Fig. 1). It cuts across north central Africa from the Benue Trough in Nigeria, through Chad and the Central African Republic into Sudan and southern Sudan. Three rifting episodes have been documented in the area. This spans from the Early Cretaceous (140-95 Ma) through Late Cretaceous (95-65 Ma) to early–middle Tertiary (65-30 Ma). During the period, about 13 km of sedimentary facies were deposited in a rift-related lacustrine settings representing three depositional cycles (McHargue et al., 1992). Boundary of each cycle is delineated regionally or locally by an angular unconformity (Lirong et al., 2013). Figure 2 shows the stratigraphic session in the Basin (Schull (1988) Kaska (1989). Abdalla et al., 2001 and Abdelhakam and Ali (2008)

The Barremian–Aptian rifting marked the first episode with more than 6000 m thick organic-rich facies of synrift sediments deposited in lacustrine environment. This includes organic-rich shales of the Abu Gabra Formation which were deposited on the Precambrian rocks. Unconformable overlying the Abu Gabra Formation is the Cenomanian-Upper Albian conglomerates and medium to coarse-grained sandstones of the post rift Bentiu Formation. It is basically an alluvial fluvial-floodplain deposits and the main reservoir rock in the area.

The Turonian – late Senonian Darfur Group represents the second rifting episode in the basin. It

Is made up of more than 4000 m sediments ranging from fluvial and deltaic claystones of Aradeiba Formation through the thin sandstone beds of Zarga and Ghazal formations to thickening upward section in the Baraka Formation. Coarse massive sandstones of the Amal Formation caps the session in the second rifting episode (McHargue et al., 1992; Lirong et al., 2013).

The third rift episode is associated with the late Eocene–Oligocene initial development of the Red Sea and the eastern arm of the East African Rift System ((Lowell and Genik, 1972; Patton et al., 1994). During the period, about 3000 m thick of lacustrine and floodplain mudstones and siltstone were deposited (Schull, 1988; McHargue et al., 1992; Tong et al., 2004; Dou, 2004; Zhang et al., 2009). The synrift sediments are unconformably overlain by a sandstone dominated Miocene sedimentary facies deposited during postrift thermal subsidence (McHargue et al., 1992; Lirong et al., 2013).

III. Samples And Methods

Less than 150μm of a total of 77 cutting samples from the great Moga & Keyi oilfields (Fig.1) in the Fula sub-basin were carefully selected for source rock analysis using Weatherford-SRA-TOC/TPH machine which is equivalent to the Rock Eval pyrolyzer. The samples were pyrolyzed to 600 °C in a helium atmosphere to obtain parameters such as the Total organic carbon content (TOC), source rock hydrocarbon potential (S1, S2 and S3) and temperature at maximum S2 peak (T_{max}) of samples were determined. Other parameters such as production index (PI), Hydrogen Index (HI) and production yield (Py) were calculated from the Rock-Eval pyrolysis data and the TOC values (Table 1). Elemental content (total sulfur, TS and organic matter, TOC, contents) was determined by passing approximately 100 mg of pulverized whole samples through elemental analyzer (Multi EA2000 model).

Bitumen extraction technique was carried-out on 45 whole rock samples (shale and clystone) using a Soxhlet apparatus. This procedure lasted for 72 hours using an azeotropic mixture of dichloromethane (DCM) and methanol (CH3OH) in ratio 93:7 respectively. . Extracted components were separated into saturated hydrocarbon, aromatic hydrocarbon and NSO compounds by liquid column chromatography. The chromatographic columns (30×0.72 cm) were packed with silica gel of 60-120 mesh, activated for 2 hours at 120 °C and capped with a few centimeters of alumina. Result of this procedure is shown on Table 2.

For petrological analyses, about 2–3 mm of the samples were embedded in Serifix epoxy resin, allowed to harden and polished to obtain a smooth surface. Microscopic examination and measurement were carried out mainly using oil immersion. Vitrinite reflectance measurements (% Ro) was performed on 54 representative samples (Tables 1& 2) using a Leica CTR6000 M Photometry Microscope, The organic matter types were described from whole rock blocks under reflected plane-polarised light and UV (ultraviolet) light. A sapphire glass standard with 0.589% reflectance value was used for calibration. The values reported were arithmetic means of at least 25 measurements per sample. The analyses were conducted at the Organic Petrology and Geochemistry Laboratories of Department of Geology, University of Malaya.

IV. Results and discussion

Table 1-3 show the result of the analyzed Great Moga and Keyi oilfields samples for the comprehensive bulk organic geochemical data, bitumen extraction procedure and organic petrography. This was basically to assess the organic matter quality, quanlity, thermal maturity and paleodepositional environment of the Lower Cretaceous Abu Gabra sediments in the Great Moga and Keyi oilfields, Fula Sub-Basin. In general, Table 1 mainly represents the summary of data from the two mentioned oilfields. There are, however, some detailed studies carried out on the Keyi oilfield's samples (Tables 2 &3). The significance of these studies will be discussed in the following sections.

4.1 Organic matter quantity

Determination of the amount of organic matter is an important requirement for assessing the potential of generating oil or gas within a sedimentary basin. (Makeen, 2015 & Ayinla et al 2017a). This is often express in terms of total organic matter content. Although, coal is an exception since it is highly rich in organic matter, acceptable minimum TOC for shale and carbonate are 0.5% and 0.2% respectively. In source rock evaluation, values of TOC need to be complimented by other data to establish the hydrocarbon potential of a basin. Peters and Cassa, 1994 as well as Ayinla et al 2017a suggested that integrated values of TOC, bitumen extracted, SRA parameters and some biomarkers signatures give better understanding of hydrocarbon potential of sedimentary basin

In this study, the SRA analysis results (of Rock-Eval equivalence) such as S_1, S_2, HI, total organic carbon (TOC) determination, extracted organic matter and hydrocarbon component contents were used to assess the source generation potential based on the organic matter richness (quantity) and Kerogen Type (quality) as shown in Tables 1 and 2. Table 1 shows the summary of bulk organic geochemical data and Sulfur content (wt %) for the analyzed Abu Gabra sediments in the Great Moga and Keyi oilfields of the Fula Sub-Basin. Samples from the Great Moga oilfield are characterized by TOC values ranging from 1.3~8.3 wt. % with overall average of >4 wt. % covering the Moga-9 (3.2 wt. %), Moga-17 (4.8 wt. %) and Moga-33 (4.0 wt. %) Wells (Table 1). Based on this TOC results, the hydrocarbon generation potential of the field is rank good to excellent (Peters and cassa, 1994; Makeen 2015 & Ayinla et al., 2017a) This is supported by the EOM results of 1331~3473 ppm , 2203~3225 ppm and 2001~3804 ppm for the Moga-9, Moga-17 and Moga-33 Wells respectively (Table 1) with an average of 2534 ppm. A similarly trend is observed from the hydrocarbon in ppm which is made up of the saturated and aromatic components ranges from 845~2444 ppm (Moga-9), 1457~1759 ppm (Moga-17) and 928~2128 ppm (Moga-33). With reference to the above parameters the hydrocarbon generation potential of the analyzed source rock is rich in organic matter and ranked good to excellent. Furthermore, the sum of volatile and remaining hydrocarbon (often denoted as S1+S2) with their averages ranging from 20.0 to 34.4.mg/g for the Great Moga wells. Note that, the maximum value of 54.5 mg/g was recorded in the Moga-33 well. In the case of the Keyi wells, 3.5~22.1, 2.7~42.9 and 3.5~14.2 mg/g were obtained for the Keyi- S1, Keyi- 5 and Keyi- N1 respectively. Thus, the studied samples have a good to excellent TOC content, good hydrocarbon genetic potential (S1+S2 = 2.7 to 54.5 (average 18.8) mg/g; Tables 1&2; e.g. Tissot and Welte, 1984) and very good to excellent hydrocarbon yields (2000>HC>2400 ppm) as shown in Table 1 and 3 (based on classification by Peters & Cassa, 1994). The potential of hydrocarbon generation in a source rock also can be estimated from TOC (%) versus hydrocarbon yield (ppm), S2 (mg HC/g rock), and S2/ S3(mg HC/g rock) (Figs 3, 4 &5). The studied samples have good to very good source rock potential which varies from mixed to predominantly oil-prone based on these crossplots.

Another source rock richness rating is obtained from a concentration of extractable organic matter total hydrocarbon content (ppm) (Figs. 6 &7). Hydrocarbons are separated from EOM using conventional column chromatography technique (Table 3; Fig. 8). Most of the samples are dominated by hydrocarbons components (saturate + aromatic). In this respect, most of the Abu Gabra samples appear to be most prolific petroleum sources where by abundant naphthenic oils might be expected to be generated.

4.2 Organic matter quality

The terms “source rock quality” has to do with evaluating the geochemical parameters that give indications of the Kerogen Type and the expected hydrocarbon product to be produced in the studied area (whether oil, gas or mixture of the two components)

Plots of T_{max} (^oC) against Hydrogen Index (HI) and (HI) against Oxygen Index (OI) were used to identify the kerogen type (quality) and maturity (e.g. Mukhopadhyay et al., 1995). Results of the analyzed Abu Gabra sediments were plotted in the HI versus T_{max} diagram to determine the kerogen type and maturity. Generally, the plot of Hydrogen Index (HI) versus T_{max} values for the analyzed samples shows that most of the samples plot in the mature stages of Type I to Type III-II region (Fig. 9). In addition to that, The HI versus OI plot can assist in identifying the three basic kerogen types (i.e. Type I “highly oil prone”, Type II “oil prone” and Type III “gas prone”) of Tissot and Welte (1984) as shown in Fig. 10. All the studied samples plot at moderate high to highest Hydrogen Index area (267 to 837mgHC/gTOC) (Table 2). This suggests that the organic matter in the studied samples contains mainly Type I and Type II kerogen (oil prone) and supported by the n-alkene/alkane doublets predominant in the Py–GC programs with n-octene to (m + p)-xylene ratio >1.0 (Fig. 11). This is in agreement with petrographic evidence showing presence of alginite and amorphous organic matter (Fig. 3) known to be associated with Type II “oil prone Kerogens.

4.3 Thermal maturity assessment

Thermal maturity determination is an importance quantity in the evaluation of a petroleum play system. This measures the extent to which heat-driven reactions have converted organic matter into kerogen and finally to petroleum in a sedimentary basin (Peters and Moldowan, 1993; Ayinla et al., 2017a & 2017b). In this study, vitrinite reflectance, SRA pyrolysis T_{max}, the production index and parameters from bitumen extraction process are integrated to have a reliable information about the organic matter thermal maturity.

It is generally accepted that vitrinite reflectance values between 0.5% and 1.3% suggest samples are within the oil generation window, whereas values less than 0.5% are commonly regarded as thermally immature. On the other hand, vitrinite reflectance values greater than 1.3% indicates gas window maturity (Tissot & Welte, 1984). For the studied Abu Gabra sediments, the mean vitrinite reflectance values are shown in Tables 1 and 2. It can be observed that the vitrinite reflectance values for the Great Moga oil fields varies from 0.59~0.72 % similar to the values in the Keyi oil oil fields (0.58~0.76 %). Although the vitrinite reflectance values for the two fields are similar, it is good to note that, on average, it is slightly high in the Keyi oil field (from 0.66~0.68 %) than the Great Moga oil field (from 0.64- 0.66 %) Based on these data, the two oil fields are within the early stage of maturity in the oil generation window. This is supported by SRA pyrolysis T_{max} values as shown in Table 2 as well as Figures 9 and 13. However, it is important to point out that abundance of liptinite macerals can give rise to vitrinite reflectance suppression as well as lowing in T_{max} value (Stach et al., 1982; Thomas, 1982; Mukhopadhyay and Dow, 1994). Thus, observed suppression of T_{max} and vitrinite reflectance of the studied samples is mostly due to high abundance of liptinite macerals (e.g. Fig. 12). Furthermore, according to Espitalié (1986) the beginning of oil formation can occur between 430^o and 435^{o}C T_{max} (corresponding to %Ro in the range of 0.5 to 0.6%) for Type I and II kerogen, and the transition to the condensate zone corresponds to a T_{max} of 455^{o}C (%Ro = 1.3%). Therefore, the studied samples from the Fula Sub-Basin have entered the oil generation window. In the same way, the production index, PI, values for the keyi oil field ranges from 0.01-0.23 mg/g with observed increase in the thermal maturity with depth especially in the Keyi 5 well. This suggests a trend of gradual increase in thermal maturity with burial depth within the area which has entered the oil window (Table 2). Similarly, the Bitumen/TOC (mg /g TOC) values ranging from 0.01-0.07 mg /g TOC recorded for the studied Fula oil field samples also indicates a range immature to earlier mature samples within the area. Meaning that, the studied samples have entered the oil generation window but probably suppressed of due to presence of high liptinite macerals

4.4 Petrographic description and Suppression of Maturity Determination Parameters

Figure 12 show photomicrographs of some of the organic forms observed under the microscope using reflected white light and same view under the UV light within a field width of 0.2mm.

This includes alginate, amorphous organic matter and structured perhydrous organic matter from Lower Cretaceous Abu Gabra sediments in the Great Moga and Keyi Oilfields, Muglad Basin:

In general, amorphous organic matter (AOM), alginite, and perhydrous which fluoresces under UV light indicates a good potential for oil and is usually of algal or other phytoplanktonic origin (Hakimi et al, 2012a & 2013; Makeen et al 2015 & 2016). In the event that the forms do not fluorescence, it simply indicates a humic origin, unless the kerogen is at a high level of maturity (Makeen et al 2015). The Abu Gabra sediments samples studied here are moderately stained with bitumen and contain abundant phytoclasts, consisting predominantly of amorphous organic matter, low reflecting alginite, and perhydrous huminite along with liptodetrinite (Fig.12). Among all the maceral groups, liptinite maceral has the lowest reflectance but highest fluorescence (under UV light) which makes it easily distinguishable. This was observed as bright yellow to yellow fluorescence of alginite and amorphous organic matter under UV light (Fig. 12 b, d and f). It is also good to note the observed prominence and high concentration of the liptinite groups under the UV- light which probably suppress the maturity determination parameters (Yang and Horsfield, 2020). Presence of a reasonable amount of liptinite maceral is known to be associated with presence of Kerogen Type I and II (of algal origin) and has potential for generation of liquid hydrocarbon.

The thermal maturity range observed for this samples as well as the previously reported early maturity by Makeen et al., 2015 & 2016 are subject to debate based on the product generated in the basin. Meaning that, a high thermal maturity of >0.8% VR is expected for the studied area as the hydrocarbon exploration in the area shows evidence that it has entered the gas window. A number of factors could suppress or exaggeratedly change the T_{max} values and influence the maturity judgments: According to Yang and Horsfield (2020) T_{max} values can be lowered if the sample is rich in hydrogen, asphaltene, sulphur and uranium, as well as carry-over effect, over mature and Rock-Eval -2 factor. It can be shifted upward if it is clay-rich, due to loading too less samples and oxidation/reworking effect. Moreover, it is known that apart from the high liptinite content in the analyzed samples, high hydrogen index (HI) values (mainly 267 to 837 mg HC/g rock) which is consistent with oil-prone Type I and Type II kerogens also has potential of suppressing the thermal maturity determination parameters (Yang and Horsfield, 2020).

Aside T_{max}, the suppression of maturity can also affect other parameters such as VR as reported in the Eocene coals of New Zealand where presence of perhydrous maceral has been responsible for lowering both T_{max} and vitrinite reflectance VR (Norgate et al., 1997; Yang and Horsfield, 2020). Similarly, Dewing and Sanei (2009) findings on a Canadian Arctic Islands borehole showed clear evidence that T_{max} values of Silurian marine shale (about 1000 m, depth) are suppressed by 10 °C at an interval containing hydrogen-rich macerals. This implies that hydrogen-rich samples like the studied Muglad Basin facies showing predominantly Type I to II have tendencies of spurious Ro and T_{max} values, Methods of correcting this anoumalies as suggested by the White Speckled Shale (Cretaceous, Canada) using an empirical calibration where T_{max} is retarded by 1 °C for every HI increment of 50 mg HC/gTOC above might be helpful (Snowdon, 1995; Chen et al., 2019), though, its efficacy is yet to be established in other petroleum systems.

Although, it generally accepted that onset of oil generation starts at a T_{max} of between 430 and 435 °C corresponding to VR of 0.6 and 1.35 %, and significant generation of hydrocarbon is expected to end when T_{max} exceeds 460–470 °C (Peters and Cassa, 1994; Chen et al., 2019; Yang and Horsfield, 2020). In the studied Sudan Basin, this must be followed with extra caution bearing in mind that there are some factors that can shift the oil generation window between the ranges as mentioned by Peters and Cassa (1994); Dembicki (2009) as well as Yang and Horsfield (2020). It is believed that the thermal maturity parameter such as T_{max} and VR do not reflect the true state of thermal maturity of the analyzed samples.

4.5 Depositional environment

Generally, throughout the Muglad Basin, the Lower Cretaceous sediments of the Abu Gabra Formation have been recognized to be deposited in a lacustrine environment (Schull, 1988). The sedimentary facies is mainly composed of dark/light brown to light grey, blocky mudstone and shale which indicates a shallow to semi-deep lacustrine environment (Rashid 2012). This is in clear agreement with the findings of the current study based on the relationship between the sulphur content and TOC (Fig. 14). Work of Makeen et al., 2015 using the results of Py-GC on a kerogen plot as well as Keym et al., 2006 further support presence of lacustrine environments associated with sedimentary facies rich in organic matter. Bivariate plot (Fig. 14) of sulphur content against TOC indicated presence of fresh water lacustrine setting within the area.

V. Conclusions

Organic geochemical and petrographic evaluation of source-rock of the Lower Cretaceous Abu Gabra organic-rich shale in the Muglad Basin, Sudan was carried out to determine the organic matter, quantity, quality and thermal maturity with evidence of suppression of thermal maturity.

The studied Abu Gabra samples have very good source rock potential (organic matter quantity) for oil generation based on the high values of TOC and high values of extractable organic matter and hydrocarbon yield. The cross plot of HI versus OI used in identifying the kerogen Types (organic matter quality) of the studied Abu Gabra sediments (i.e. Type I "highly oil prone" and type II "oil prone" as shown Fig. 13). This is also supported by a significant presence of alginite and amorphous organic matter and confirmed by the n-alkene/alkane doublets predominant in the Py–GC programs. For the thermal maturity, vitrinite reflectance (0.58-0.76%Ro) and T_{max} values (432–442^{o}C) indicate that the Abu Gabra sediments have entered an early mature to marginally mature oil generation window. However, the vitrinite reflactence and T_{max} values in the formation might be suppressed, for the sequence is liptinite rich and possibly contains perhydrous organic matter. Moreso, evidence shows that the area has entered the gas generation window.

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Figures Captions

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Figure 2: Regional stratigraphy of the Muglad Basin, southern Sudan (after Schull, 1988; Lirong et al., 2013).
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Figure 10: Plot of oxygen index versus hydrogen index for the analysed samples; indicating most of these samples are Type I and Type II kerogen

Figure 11: Py–GC pyrograms of the analysed Abu Gabra sediments showing n-alkene/alkane doublets suggesting good oil generating potential (the first two pyrograms are adapted from Makeen et al., 2015).

Figure 12: Photomicrographs of alginate, amorphous organic matter, and structured perhydrous organic matter from Lower Cretaceous Abu Gabra sediments in the Great Moga and Keyi Oilfields, Muglad Basin: a, c and e are taken under reflected white light and b, d and f are same view as a, c, e respectively under UV light, field width = 0.2mm.

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Figure 14: Plot of sulphur content versus TOC, suggesting that the depositional environment the analysed sediments was dominantly freshwater lacustrine environment (modified after Berner and Raiswell, 1983).

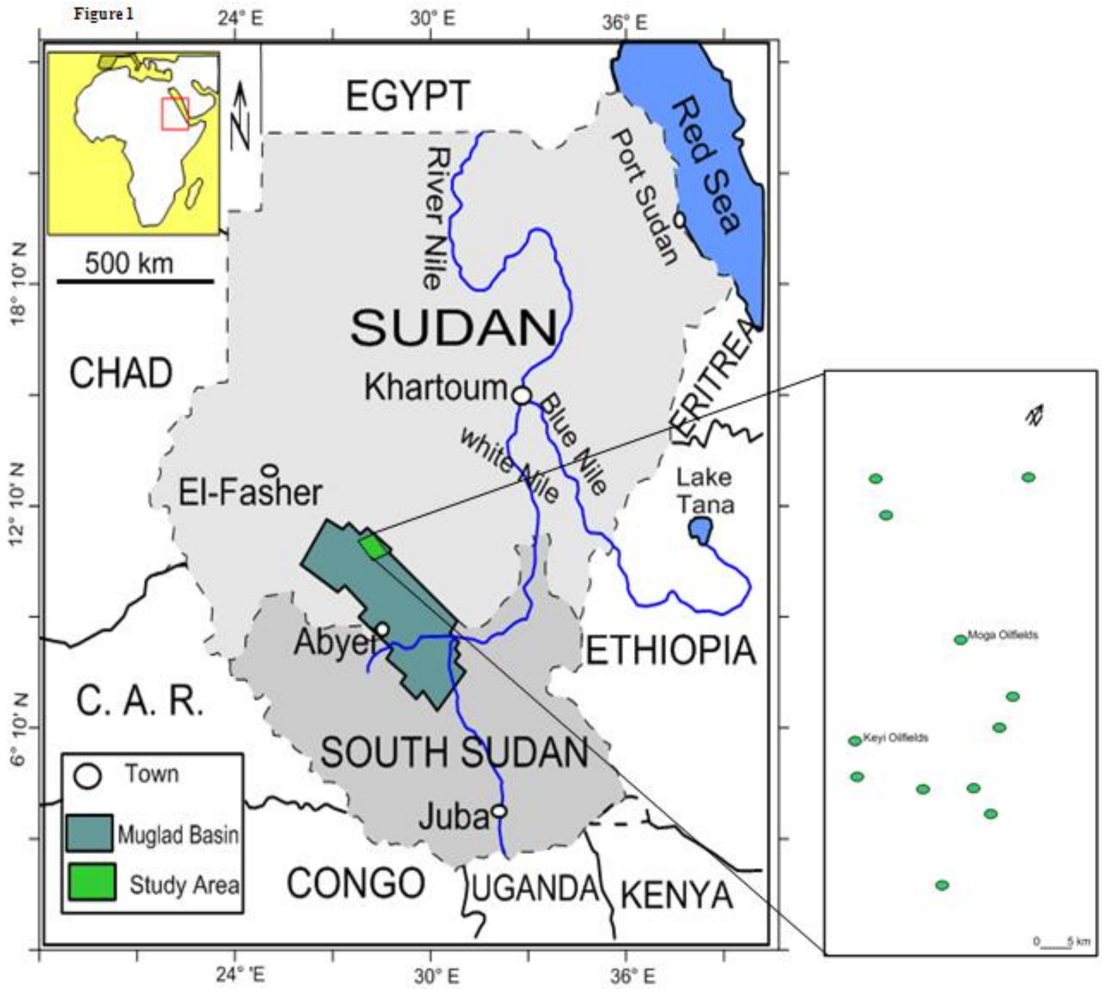

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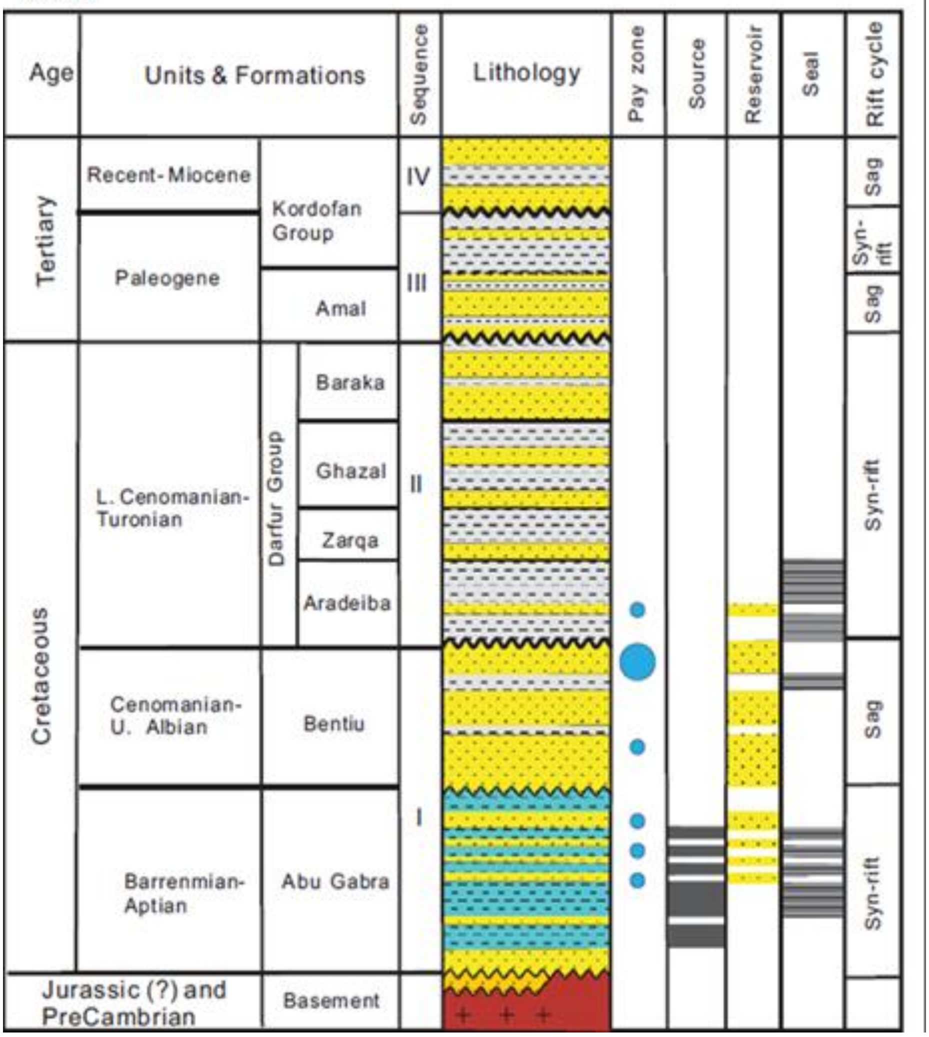
Figure 2



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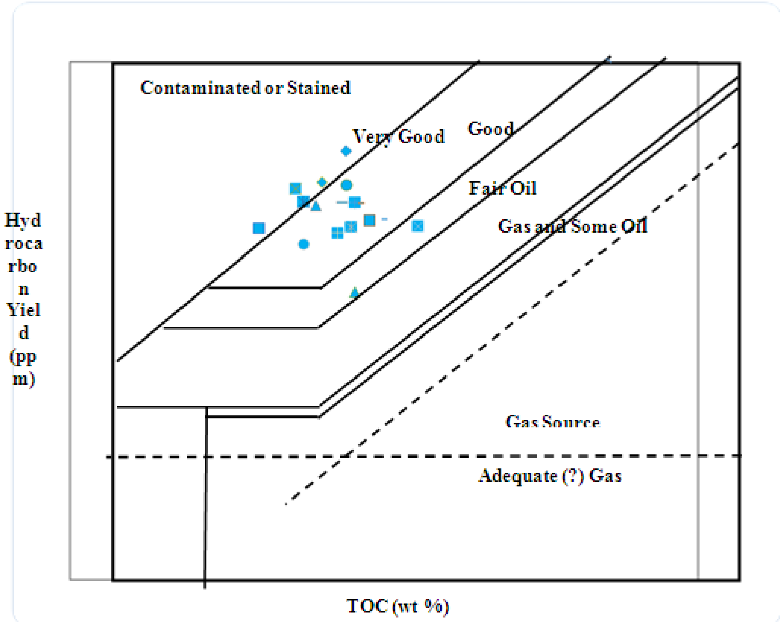

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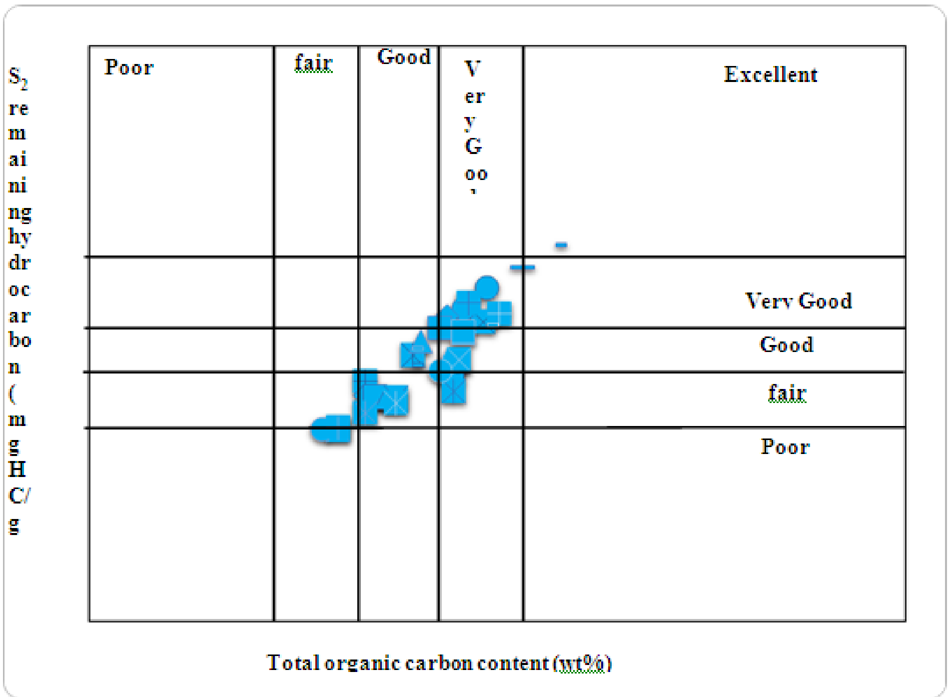

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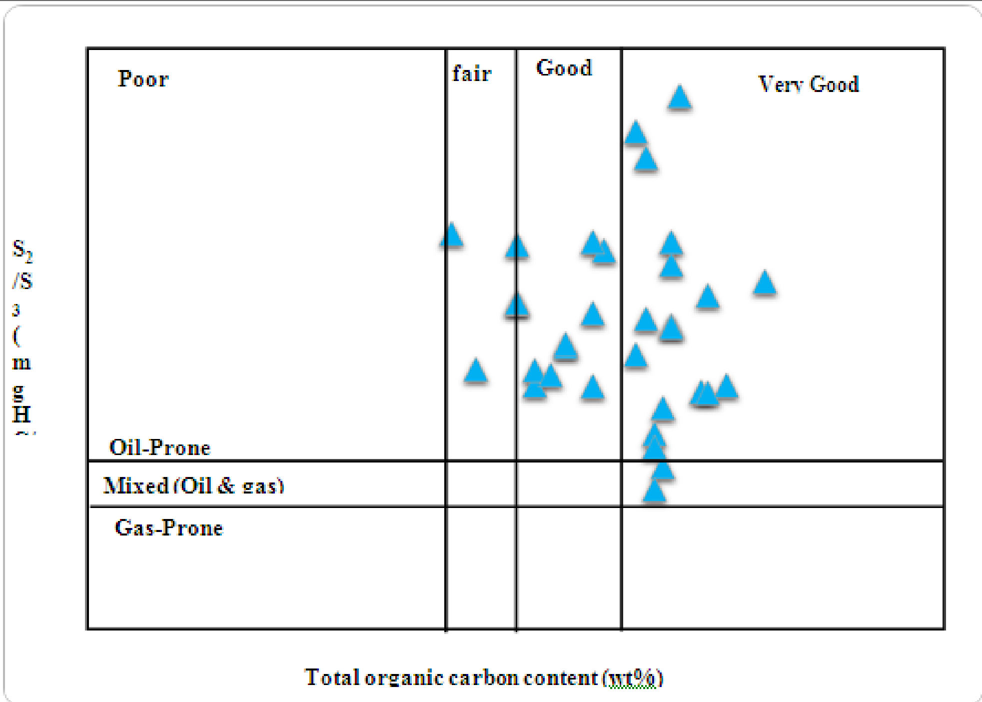

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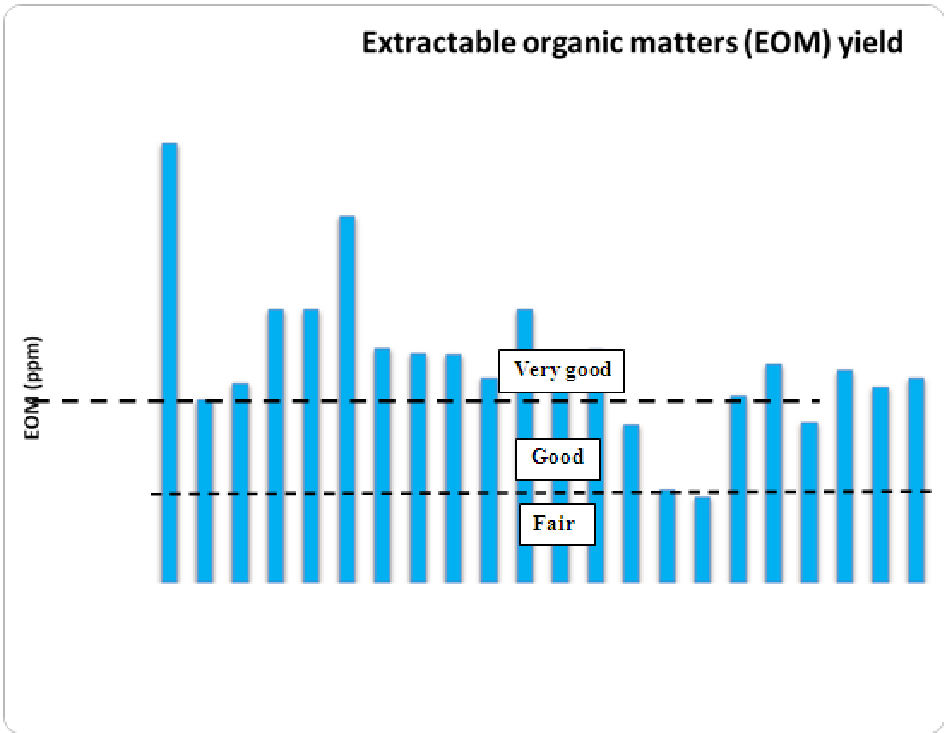

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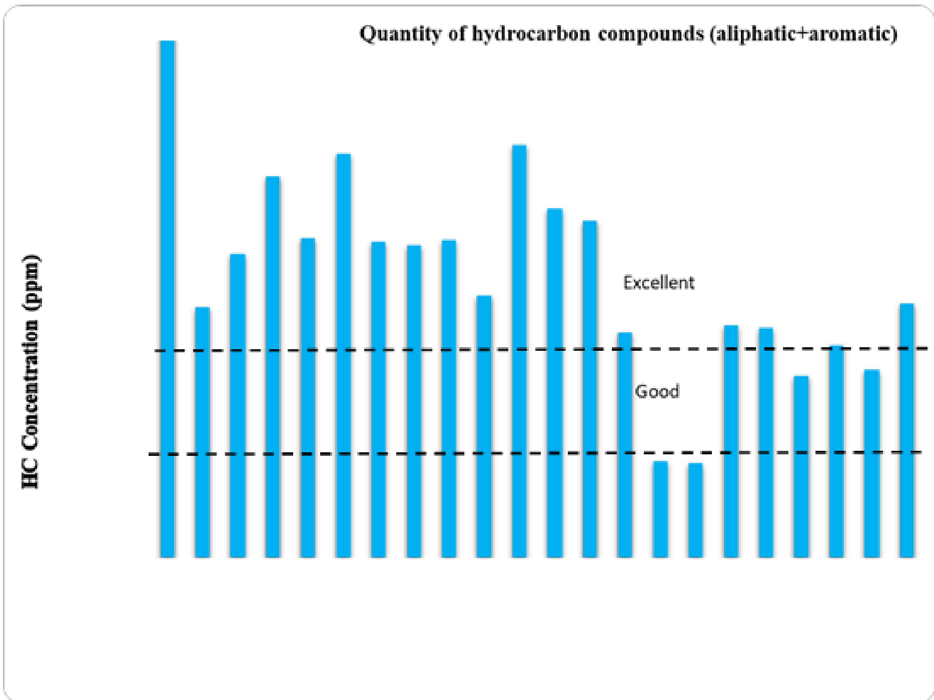

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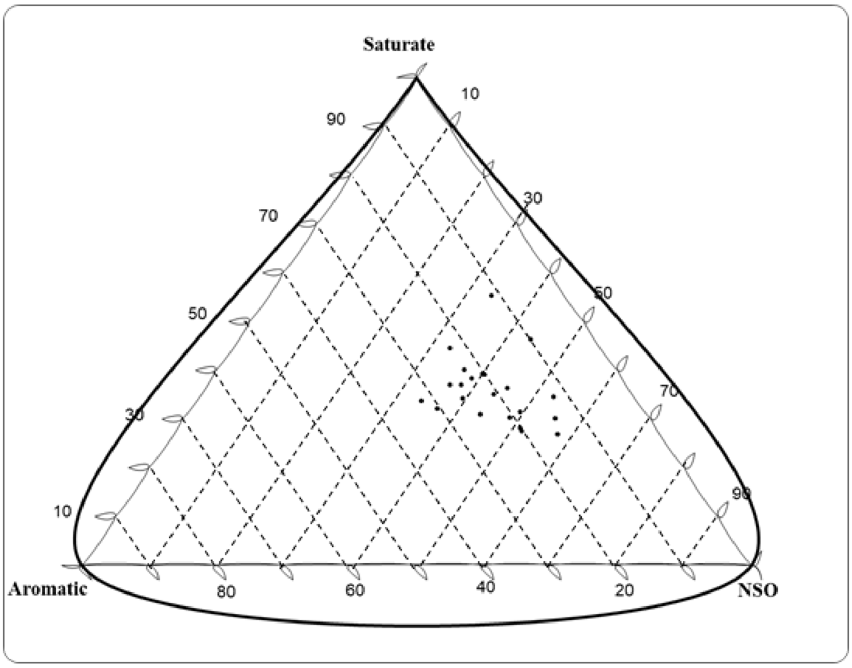

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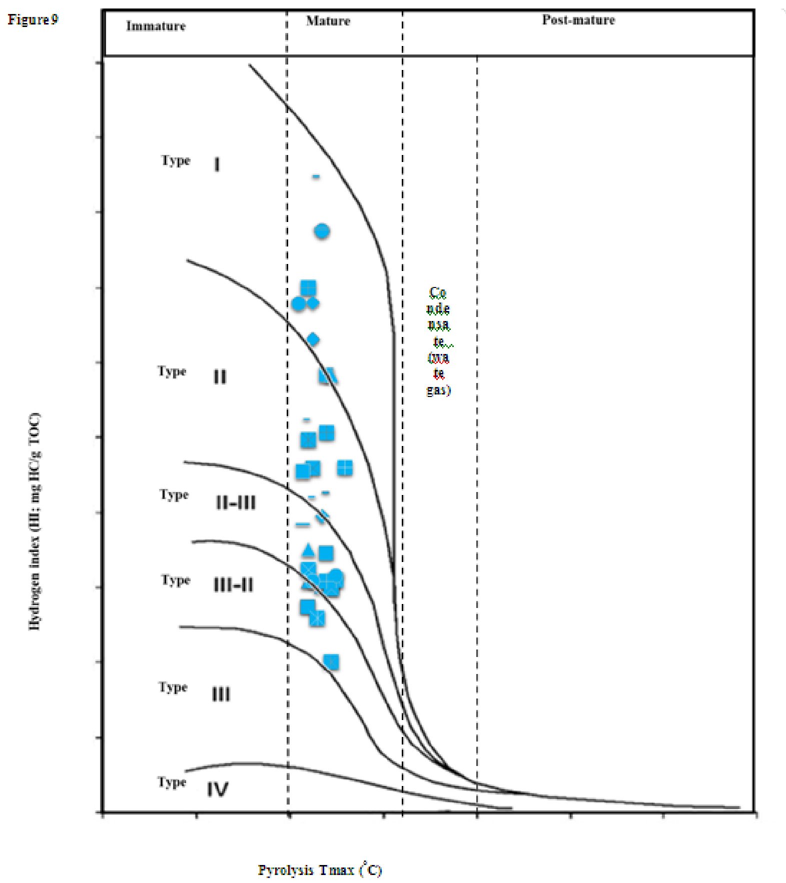

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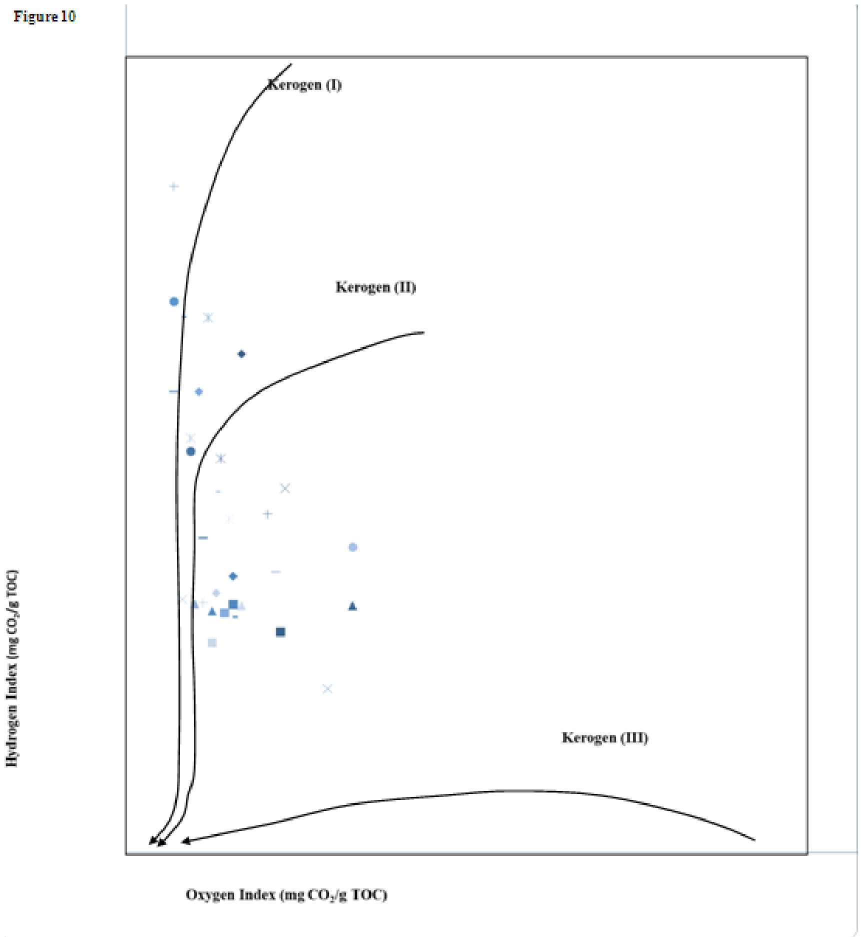

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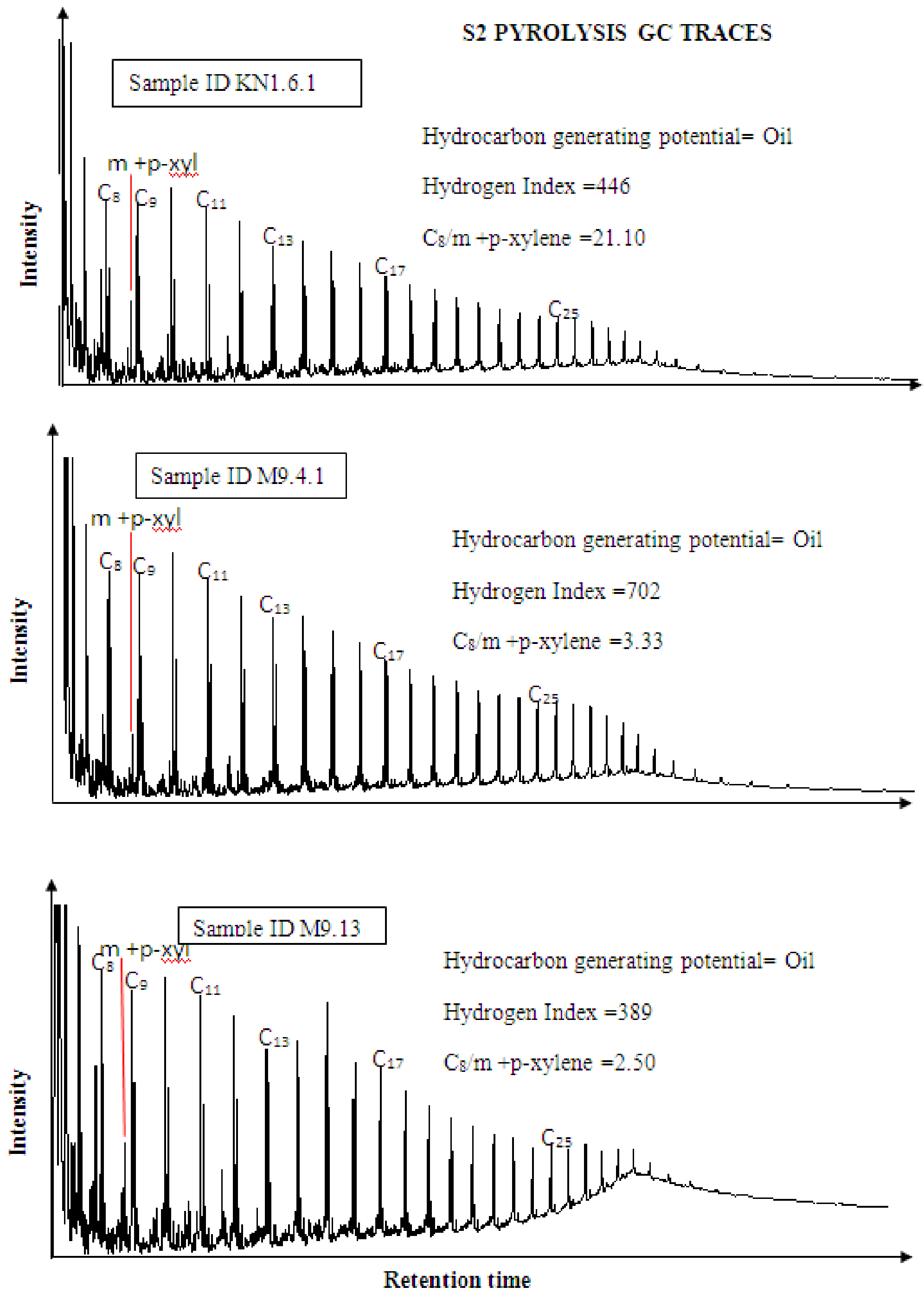

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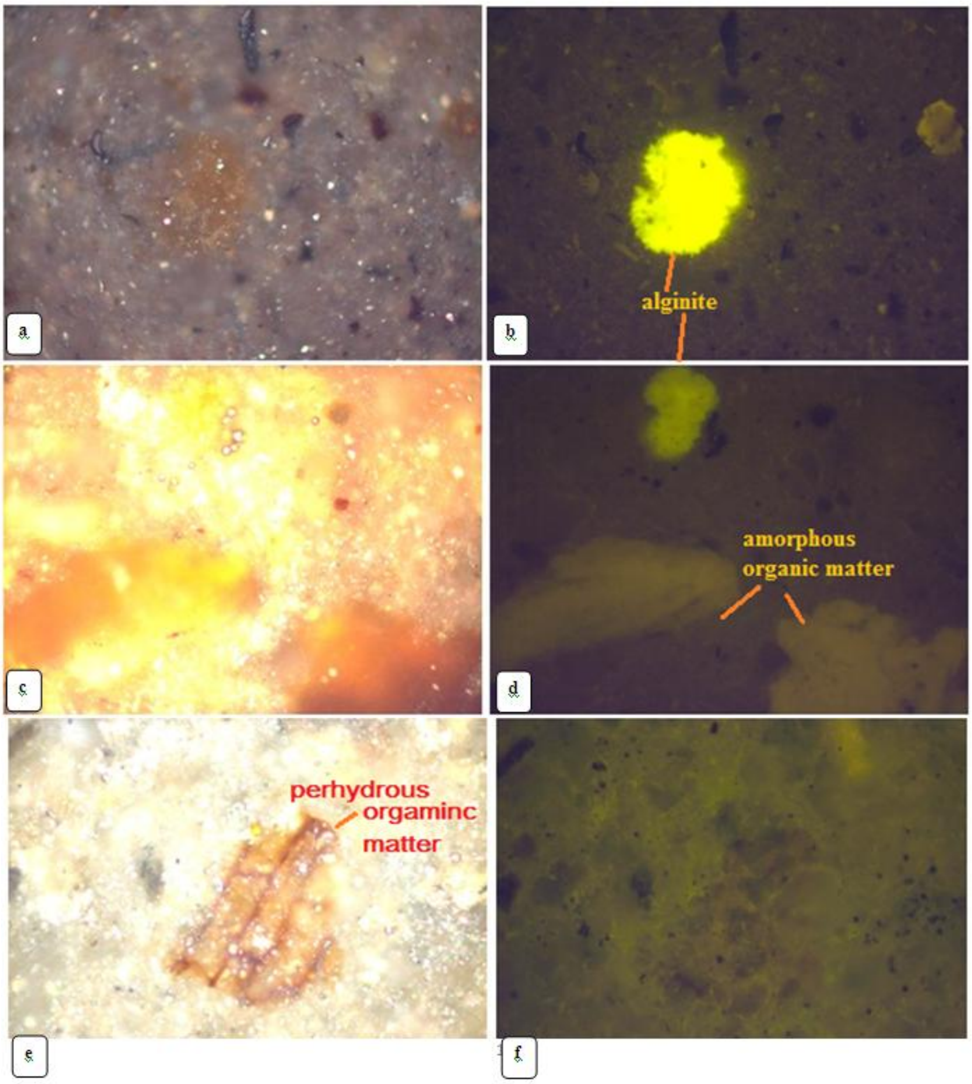

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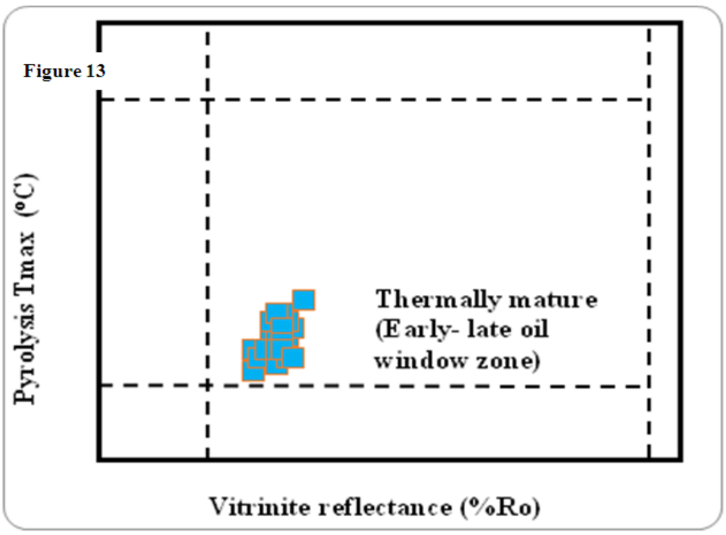

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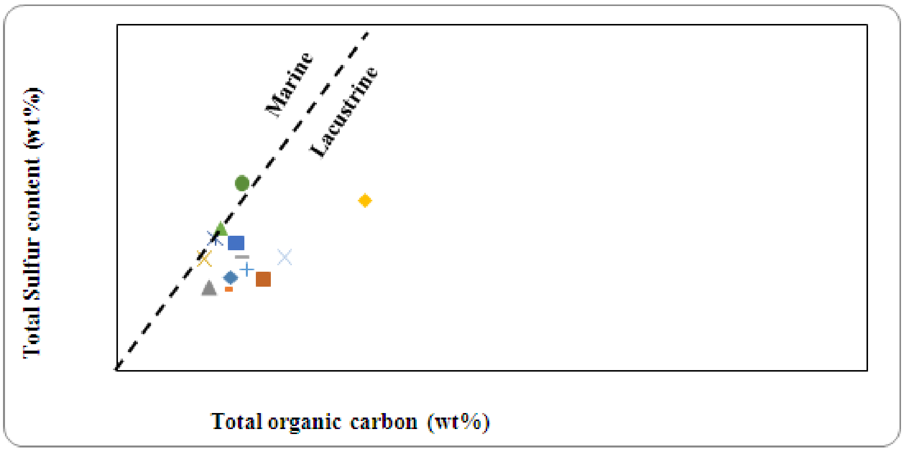

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Table 1. Summary of bulk organic geochemical data and Sulfur content (wt %) for the analysed Abu Gabra sediments in the Great Moga and Keyi oilfields, Fula Sub-Basin. Some of the data are reproduced from Makeen et al., 2015. (Denominator is the range; numerator is the average; figures in brackets denote numbers of samples).

Oilfields	Wells	Interval (m)	TOC (%)	S1+S2 (mg/g)	EOM (ppm)	HC (ppm)	Rank	Sulfur Content (wt%)	R_o (%)
Great Moga	Moga-9	1600-1850	1.6~4.6 3.20 (11)	7.2~33.7 20.0 (11)	1331~3473 2006 (10)	845~2444 1176 (10)	Good-excellent	0.34~1.05 0.62 (7)	0.59~0.70 0.66 (10)
	Moga-17	1555-1760	3.6~7.2 4.8 (11)	20.9~45.4 34.4 (11)	2203~3225 2876 (7)	1457~1759 1645 (7)	Good-excellent	0.66~2.06 1.05 (5)	0.63~0.67 0.64 (8)
	Moga-33	1480-2115	1.3~8.3 4.0 (11)	4.3~54.5 29.3 (11)	2001~3804 2721 (6)	928~2128 1606 (6)	Good-excellent	0.14~1.21 0.70 (5)	0.59~0.72 0.65 (10)
Keyi	Keyi-S1	2115-2395	1.0~2.8 1.7 (16)	3.5~22.1 7.1 (12)	2023~4871 3198 (6)	1210~3052 1845 (6)	Good-excellent	0.48~0.72 0.55 (6)	0.59~0.73 0.66 (11)
	Keyi-5	1555-2380	0.7~5.0 1.8 (14)	2.7~42.9 13.6 (12)	1736~3023 2473 (8)	1090~1995 1529 (8)	Good-excellent	0.26~1.09 0.53 (7)	0.58~0.74 0.66 (11)
	Keyi-N1	1480-2770	1.3~4.6 2.4 (16)	3.5~14.2 8.3 (9)	937~2410 1871 (8)	457~1227 898 (8)	Good-excellent	0.65~2.06 0.80 (8)	0.62~0.76 0.68 (9)

Table 2 Results of pyrolysis and TOC analyses with calculated parameters and measured vitrinite reflectance values (%Ro) of the Abu Gabra sediments in the Keyi oilfield, Fula Sub-Basin (Some of the data are reproduced from Makeen et al., 2015).

Wells	Sample I	Depth (m)	Pyrolysis data										R_o (%)
			TOC Wt%	S_1 (mg/g)	S_2 (mg/g)	S_3 (mg/g)	S_2+S_3 (mg/g)	S_2/S_3 (mg/g)	T_{max} (oC)	HI	OI	PI (mg/g)	
Keyi- S1 Well	KS1-1	2115	2.3	0.34	14.4	0.39	14.7	36.9	435	622	17	0.02	0.60
	KS1-15	2185	2.1	0.12	5.6	0.55	5.7	10.2	434	267	26	0.02	0.59
	KS1-19	2220	2.2	0.11	6.6	0.95	6.7	6.9	434	301	43	0.02	0.65
	KS1-9	2225	2.8	0.83	21.2	0.00	22.1	--	437	765	0	0.04	0.65
	KS1-10	2230	1.0	0.23	4.8	0.05	5.1	96.0	438	498	5	0.04	0.66
	KS1-2	2235	1.5	0.80	6.1	0.34	6.9	17.9	437	418	23	0.12	0.67
	KS1-7	2260	1.1	0.37	3.1	0.17	3.5	18.2	437	286	15	0.11	0.66
	KS1-8	2345	1.0	0.46	3.8	0.08	4.2	47.5	437	387	8	0.11	0.69
	KS1-6	2355	1.1	0.38	3.7	0.17	4.1	21.8	438	338	15	0.09	0.69
	KS1-5-1	2375	1.2	0.36	3.7	0.18	4.1	20.6	439	302	15	0.09	0.67
	KS1-4-1	2385	1.3	0.34	3.7	0.13	4.0	28.5	439	294	10	0.08	0.70
	KS1-11	2395	2.1	0.23	4.1	0.78	4.3	5.3	439	195	37	0.05	0.73

Keyi- 5 Well	**K5-3**	1980	2.3	0.47	15.2	0.20	15.7	76.0	432	669	9	0.03	0.60
	K5-5	2155	2.4	0.76	16.8	0.03	17.6	560.0	434	690	1	0.04	0.64
	K5-3-1	2160	5.0	1.38	41.5	0.04	42.9	1037.5	435	837	1	0.03	0.65
	K5-1-1	2170	3.8	1.35	28.9	0.00	30.3	--	437	768	0	0.04	-----
	K5-4	2195	2.0	0.57	13.4	0.05	14.0	268.0	435	670	3	0.04	0.65
	K5-2-1	2235	1.9	0.90	11.0	0.03	11.9	366.6	438	574	1	0.08	0.65
	K5-6-1	2270	1.5	0.98	9.0	0.10	10.0	90	439	574	7	0.10	0.65
	K5-8	2275	0.8	0.68	2.2	0.10	2.9	22	439	292	13	0.23	0.66
	K5-7	2280	1.0	0.71	2.9	0.06	3.6	48.3	440	303	6	0.20	0.66
	K5-1	2285	0.7	0.48	2.2	0.02	2.7	110.0	440	309	3	0.18	0.67
	K5-2	2295	0.8	0.40	2.3	0.00	2.7	--	438	301	0	0.15	0.70
	K5-4-1	2380	1.5	0.50	7.9	0.08	8.4	98.75	433	515	5	0.06	0.74
Keyi- N1 Well	**KN1-7**	2255	2.3	0.06	8.6	0.99	8.7	98.8	433	376	43	0.01	0.62
	KN1-5-1	2265	2.1	0.07	6.5	0.18	6.6	8.7	435	305	8	0.01	0.64
	KN1-6-1	2310	2.3	0.1	10.4	0.26	10.5	36.1	433	446	11	0.01	0.65
	KN1-8	2350	2.0	0.04	6.7	0.48	6.7	40.0	434	344	25	0.01	0.66
	KN1-5-1	2380	2.3	0.08	6.8	0.23	6.9	13.9	434	317	11	0.01	0.67
	KN1-6-1	2385	1.7	0.07	3.4	0.13	3.5	29.6	436	253	10	0.02	0.67
	KN1-2	2390	1.9	0.07	5.6	0.31	5.7	26.2	435	301	17	0.01	0.68
	KN1-1-1	2765	3.1	0.13	14.1	0.85	14.2	18.1	442	452	27	0.01	0.76
	KN1-2-1	2770	2.8	0.06	11.5	0.39	11.6	16.6	434	412	14	0.01	0.76

Table 3. Bulk geochemical results of extractable organic matter (EOM) yields (ppm), relative proportions of saturated hydrocarbon fractions, aromatic hydrocarbon fractions, and NSO compounds of the EOM (in wt%) of the analysed Abu Gabra sediments in the Keyi oilfield, Fula Sub-Basin

Wells	Samples ID	Depth (m)	Sulfur Content (wt%)	Bitumen extraction and chromatographic fractions (ppm of whole rocks)					Chromatographic fractions of Bitumen Extraction (EOM wt%)				Bitumen	TOC (Wt.%)	Bitumen/TOC (mg /g TOC)
				EOM	Sat.	Aro.	NSO	HCs	Sat./ EOM	Aro./ EOM	NSO/ EOM	HCs			
Keyi-S1 Well	**KS1-15**	2180	0.54	4870.6	1558.2	1493.7	1807.5	3051.8	32.0	30.7	37.1	62.7	0.09	2.1	0.04
	KS1-17	2195	0.53	2023.1	691.4	518.6	808.1	1210.0	34.2	25.6	39.9	59.8	0.03	2.7	0.01
	KS1-3	2210	0.48	2200.8	978.2	489.1	724.4	1467.2	44.4	22.2	32.9	66.7	0.04	1.5	0.03
	KS1-5	2370	0.50	3017.1	1112.9	732.0	1156.6	1844.9	36.9	24.3	38.3	61.1	0.06	1.2	0.05
	KS1-4	2380	0.51	3023.9	912.3	630.4	1478.6	1542.6	30.2	20.8	48.9	51.0	0.06	1.3	0.04
	KS1-11	2385	0.72	4054.8	1141.0	812.2	2089.1	1953.3	28.1	20.0	51.5	48.2	0.06	2.1	0.03
Keyi-5 Well	**k 5 - 3**	1980	1.09	2587.6	1009.7	516.6	1051.2	1526.3	39.0	20.0	40.6	59.0	0.05	2.3	0.02
	K 5 - 5	2155	0.59	2528.7	991.7	517.0	1018.0	1508.7	39.2	20.4	40.3	59.7	0.05	2.4	0.02
	K 5 - 4	2195	0.47	2525.8	964.4	569.4	988.4	1533.8	38.2	22.5	39.1	60.7	0.05	2.0	0.02
	K 5 W	2240	---	2254.6	1044.8	220.0	990.0	1264.8	46.3	9.8	43.9	56.1	0.04	---	---
	K5. 6	2265	0.59	3023.4	1667.9	327.5	1016.4	1995.4	55.2	10.8	33.6	66	0.06	1.6	0.04
	K 5 - 8	2275	0.28	2555.3	860.9	824.6	866.0	1685.4	33.7	32.3	33.9	66.0	0.05	0.8	0.06
	K 5 - 1	2285	0.26	2576.2	954.2	672.7	942.2	1626.8	37.0	26.1	36.6	63.1	0.05	0.7	0.07
	K 5 - 2	2290	0.43	1735.7	695.3	394.5	643.0	1089.8	40.1	22.7	37.1	62.8	0.03	0.8	0.04
Keyi-N1 Well	**K N 1.7**	2255	0.66	1017.9	279.9	182.4	529.5	462.3	27.5	17.9	52.0	45.4	0.02	2.3	0.01
	K N 1.4	2270	1.06	936.6	294.0	162.9	466.8	456.9	31.4	17.4	49.8	48.8	0.02	2.0	---
	K N 1.3	2275	0.99	2065.5	747.1	373.5	939.9	1120.6	36.2	18.1	45.5	54.3	0.05	4.6	---
	K N 1.5	2355	0.74	2409.7	832.4	276.0	1283.0	1108.5	34.5	11.5	53.2	46.0	0.05	2.2	0.02
	K N 1.6	2360	0.65	1767.5	544.8	332.9	780.5	877.7	30.8	18.8	44.2	49.7	0.03	1.3	0.02
	K N 1.2	2365	0.83	2344.8	703.4	320.5	1308.7	1023.9	30.0	13.7	55.8	43.7	0.06	1.9	0.03
	K N 1.1	2760	0.77	2162.7	579.3	328.3	1248.6	907.6	26.8	15.2	57.7	42.0	0.05	3.7	---
	K N 1.1.1	2765	0.66	2261.4	789.1	437.8	996.3	1226.9	34.9	19.4	44.1	54.2	0.05	3.1	0.01