PRJ Vol I, (January 1989); P. 17–28, 13 FIGS.

HYDROCARBON HABITAT IN THE SIRTE BASIN NORTHERN LIBYA

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دراسة صخور المصدر الهيدروكربونية فى حوض سرت

مصطفى العلمى ، سلامة رحومة ، د . أ . بات

القت هذه الدراسة الضوء على اهم صخور المصدر بحوض سرت وهى تكوين سرت الطفلى بتحديد سحناته الرسوبية والبيئية وتقييم وضعه الطبقى والتركيبى والذى تمثل فى جملتها العوامل المتحكمة فى توليد النفط وهجرته وتجمعه فى حوض سرت .
وتم اعتمادا على ربط المعلومات الجيولوجية بالبيانات الجيوكيميائية تقييم تكوين سرت تقييما اقليميا يغطى مختلف مقاطع الحوض وذلك لغرض استنتاج طاقته المولده للمواد الهيدروكربونية مما يساعد فى عمليات الاستكشاف مستقبلا . كما تم توضيح المناطق الرئيسية المولدة للنفط والمولدة للغاز . هذا وتعتبر جميع المكامن النفطية القريبة من صخور المصدر مهمة وتقل درجة اهميتها بزيادة المسافة بين المكمن وهذه المناطق الرئيسية ويعتقد هنا أن اغلب النفط فى حقول حوض سرت كانت قد تولدت من صخور تكوين سرت الطفلى ويستثنى من ذلك نفط حقول ابو الطفل والسرير وأمال والحقول الواقعة بعقد امتياز 80 حيث يعتقد أن النفط هناك تولد من صخور قارية .

ABSTRACT

The Oil-Prone organic facies II of the marine Upper Cretaceous (mainly Campanian) Sirte Shale, including its micritic facies, developed in the eastern Sirte Basin, occupies the central part of the "Oil generative depressions", where the depth of burial is sufficient for thermal maturation. This is based upon a large amount of geochemical data collected over the last years by the Petroleum Research Centre .

The combination of favourable organic facies and maturation level of the Sirte Shale defines the areas of major oil generation in the Zella Trough, the Marada Trough (also called the Hagfa Trough) and the Agedabia Trough. The giant oil fields tend to occur within short distance migration range from these oil-generative depressions.

The evolution of the various segments of the Sirte Basin, in terms of their remaining potential hydrocarbon prospects, can be made by employing conventional methods of petroleum geology in conjunction with precise knowledge of where and when oil was generated in the various segments of the basin.

INTRODUCTION

The Sirte Basin with its series of northwest-southeast trending horst and graben blocks forms an important structural province of Northern Libya (Figure 1). It is a prolific oil producing basin and is considered to contain more than one adequately mature source rock. Reports of petroleum geochemical studies so far remain unpublished (e.g. Robertson Res. Int. 1979) and have been largely restricted to each operator's area of interest. However, the available petroleum geochemical studies do not throw sufficient light on the mode of formation and stratigraphical position of these effective hydrocarbon sources in the basin as a whole. An attempt has therefore been made to consolidate the available source rock data of 88 wells covering the Sirte Basin (Figure 2) and to integrate the data with the results of geochemical investigations of 57 oil samples in order to identify the regional source-bed occurences. The outcome is also used to assess the potential hydrocarbon prospects of the various parts of the Basin.

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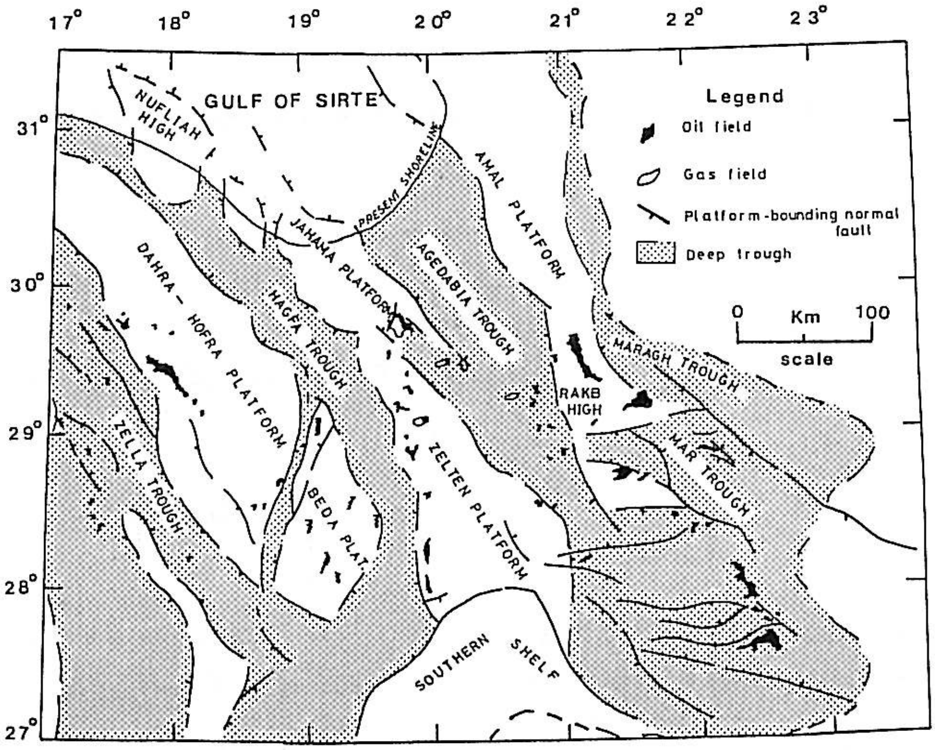

FIG. 1. Major tectonic elements of Sirte Basin, Libya. (After El-Mouzughi and Taleb, 1981)

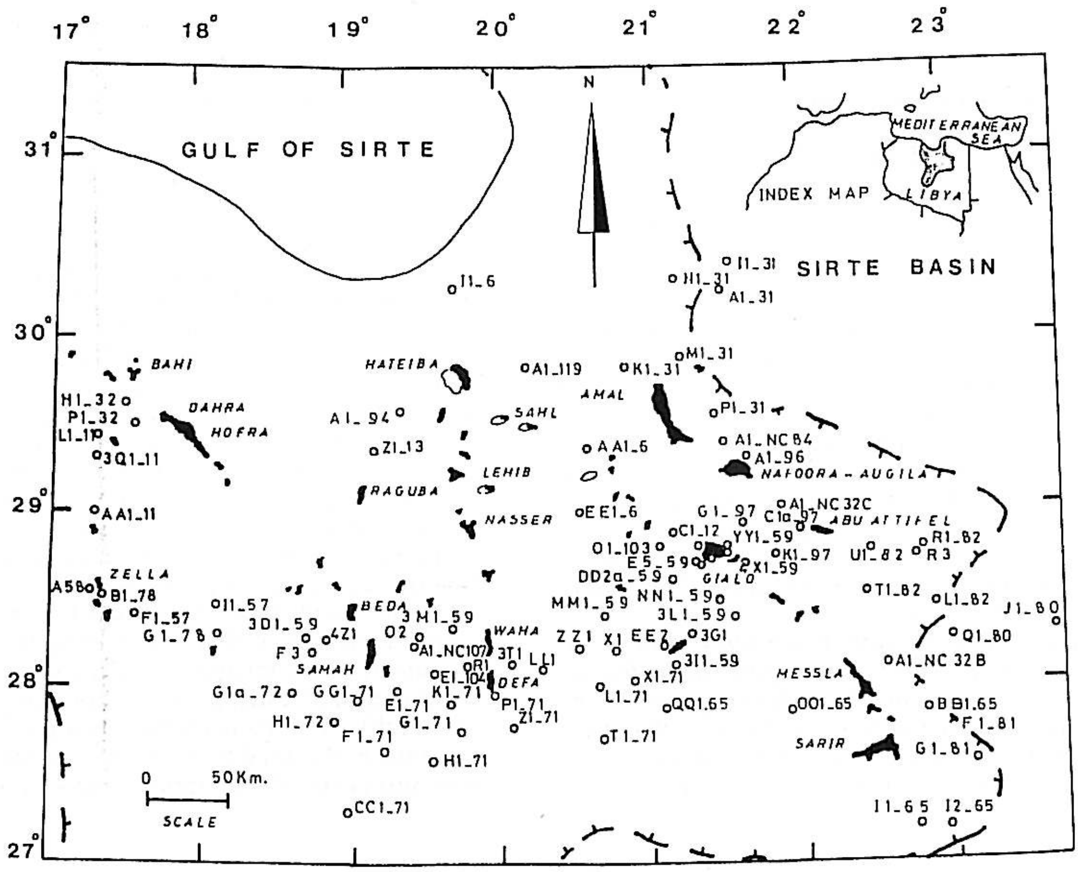

FIG. 2. Location map showing the wells of source rock study.

The attempt here involves studies of richness, maturation, oil to source-rock correlation, time of oil generation and migration. Stratigraphic principle and organic facies concepts due to Demaison et al (1983) are additionally employed. The marine Upper Cretaceous (mainly Campanian) Sirte shale is concluded to possibly constitute the prime source-rock for hydrocarbon generation and accumulation because of the favourable depositional environment, organic carbon contents, stratigraphic and structural setting characterising the formation.

The Sirte shale is a widely distributed stratigraphic unit of the Basin. It occurs dominantly as a laminated, carbonaceous, non-bioturbated sequence of dark grey to mainly dark brown shales grading into shaly limestone at the lower part. In the eastern Sirte Basin, however, the lower part of the shale passes into a calcareous facies, namely the Tagrifet limestone (Barr and weegar, 1972). In relation to this region. Sirte Shale is used as restricted to the upper shale sequence. Williams (1968) referred to it as Rakb Shale. In so far as the source-rock evaluation attempted in the present work is concerned, the Sirte Shale (Sensu stricto) includes the whole sequence of the formation and its equivalent, the Tagrifet Limestone.

In general, the bulk of the oil is derived from the Sirte Shale. Locally, however, in the eastern Sirte Basin, oil is also derived from source rocks deposited under paralic to continental environments that dominated in the Turonian and Lower Cretaceous times. Paleogeographic distribution of the source beds for these oils which have significantly high content of wax is little known.

The traps within or adjacent to generative troughs are important as exploration targets. This is because of the occurence of the source rock, the migration distances which are likely to be short or moderate and the conductive geologic setting for the entrapment of hydrocarbons, all resulting from the horst-graben tectonic fabric present in the region. In the present work, the model of hydrocarbon occurence and entrapment is studied based on the examination of the geological and petroleum geochemical characteristics to finally demarcate the effective hydrocarbon source rocks in the Sirte Basin.

REGIONAL SETTING

The Sirte Basin persisted from the Silurian until the Jurassic as an extensive uplifted tract with NW-SE orientation consequent upon the trend of Caledonian movements (Massa, 1984). The eroded arch was rifted to form the Sirte Basin aided by tensional movements in the Late jurassic. Sedimentation began in Early Cretaceous time when nonmarine to parallic sediments of the Nubian formation started to accumulate in small grabens.

Full scale rifting and block faulting took place in Upper Cretaceous time. This lead to marine transgression and associated subtle facies changes across the lines of contemporaneous faults. Difficulties of nomenclature exist obviously due to the abrupt changes in depositional conditions.

This main NW-SE synclinal trough remained active during the tertiary as the Basin continued to subside. In general, all the structural highs came to be masked by the later, Tertiary sedimentation and by mid Paleocene time, the region developed into a unique Basin (Roberts, 1970). Intense tectonic activity returned again during the Oligocene and Early Miocene bringing about the regional uplift. Towards the end of Middle Miocene the present onshore part of the Sirte Basin had emerged.

DEPOSITIONAL ENVIRONMENTS

The unique basin geometry of the Sirte Basin with opening into the Mediterranean indicate marine transgression to have taken place from the north during the Campanian time (Figure 3). The northerly open marine conditions permitting active intermixing of water masses led to oxigenation environment. Presence of planktonic foraminifera throughout the formation in the northern Sirte Basin together with benthonic foraminifera (Barr and Weeger, 1972) corroborates the indication of open marine and outer neritic environment. The paleoceanographic factor is suggestive of minimum possibilities for petroleum source bed deposition (Demison and Moore, 1980).

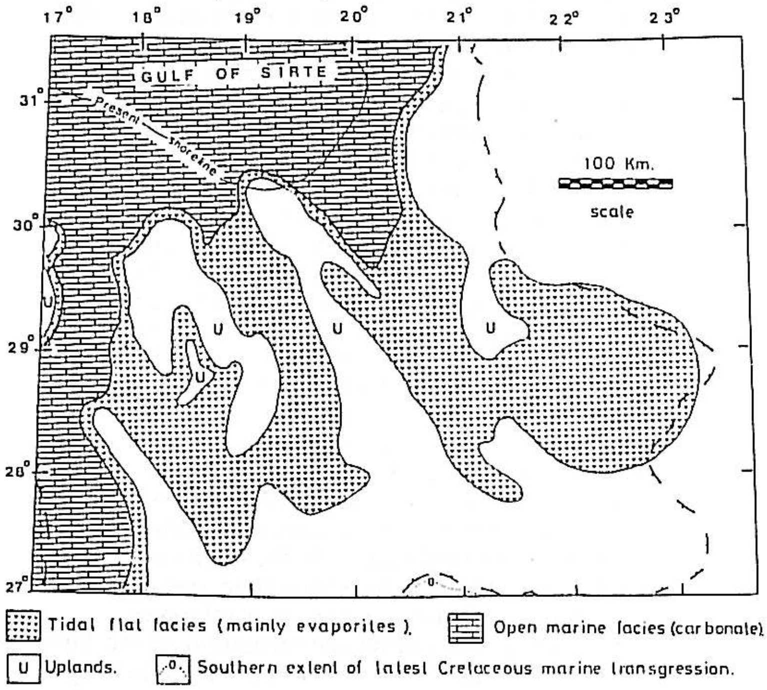

FIG. 3. Paleogeographic map of transgressive Turonian deposits, as based on the analysis of Etel evaporites and its basinward equivalent, Sirte Basin, Libya.

Longitudinal trough areas, however, gave rise to restricted marine environments further into the interior of the Basin. These formed tracts of inactive mixing of water masses with tendency to development of stagnant waters. Barr and weeger (1972) reported that the lower part of the Sirte Shale, barring the northern part of the Basin, contain small sized bulimines. At the same time, the upper parts of the sequence abound in both planktonic and benthonic foraminifera. The most ubiquitons of the benthonic foraminiferal species appears to be the Siphogeneranoides Cretacea. The most conspicuous of the small size bulimines in the lower part of the Sirte Shale is the Bulimina Prolixa (Cushman and Parker, 1947) which points to the prevalence of a restricted marine environment. Such environments lead to reducing (depletion of oxygen) conditions. It indicates the tendency towards development of stagnant waters as it becomes a zone of insufficient mixing of water masses (Demaison et, 1983). Moreover, the bulimines are known to tolerate such stressed environments of stagnant conditions with low level oxygen (Haynes, 1981). Consequently, they buildup small, smooth and thin skeletons vis-a-vis the normal marine milieu. Higher up in the formation, a tendency towards amelioration of marine reducing environment occurs as indicated by the presence of both planktonic and benthonic foraminifera.

The Tagrifet Limestone (lateral) facies equivalent of the lower part of the Sirte Shale) is located in the eastern part of the basin. It has been described in detail as the Rakb Carbonates by Williams (1968) who concluded that the upper micritic unit of the Rakb Carbonates was deposited in a low energy, open sea environment in water depths of about 34-45 meters. It probably forms some of the source beds, while its lower unit in the Augila-Nafoora Fields is considered as a reservoir rock deposited in shallow marine environment (epineritic) as the sea transgressed across the basement highs. The Tagrifet Limestone is generally a dark brown, oil-saturated and argillaceous planktonic micrite containing a few very fine grains of dolomite and pyrite. Traces of phosphatic grains are scattered throughout. While the biofacies is recognized by Globotruncana and Heterohelix faunas filled with calcite or pyrite, non bioturbated and the benthic fauna is sparse and consists solely of rare Incoeramus sp. fragments. The lithology and fauna may be considered as evidence of an oxygen-depleated, low energy and shallow marine basin which had only access to the open ocean in the north where the oceanic currents in surface waters probably raised the number of planktonics.

It is likely that during sedimentation of the Sirte Shale and its equivalent rocks there was continuity in the growth of tectonic structure into horst-graben fabric in a shallow marine basin. A great deal of subsidence and transgression may have taken place alongside the tectonic develoment. The flow of surface currents was persistantly towards the Basin (positive input) which may have caused continual supply and concentration of nutrients (phosphates and nitrates). In addition, the plant nutrients such as phosphates and nitrates were carried into the seas in the grabens by fluvial drainage systems. These systems transported solutes leached from soil in the horsts to the grabens. Presence of phosphate nodules in Sirte Shale evidences the possibility.

The mineral nutrients in the presence of light lead to prolific primary biologic productivity resulting in the depleation of oxygen. The semi-enclosed seas confined to the grabens possibily promoted water stratification to increase the oxygen depleation. Evidence of anoxic sedimentation associated with continual supply of nutrients is found in the Sirte Shale in the form of laminations, attainment of brownish black colour presence of phosphate nodules and pyritic-concentrations, non-bioturbated sequence and finally by general absence of macrofossils. These features are apparent in the Sirte Shale of the type section encountered in well 02-59.

In conclusion it is possible to extend the source bed depositional model of silled basin reinforced by transgression to the basin during the period of deposition of the Sirte Shale.

SOURCE BED EVALUATION

The quantity of organic material in a rock, the oil generative quality of the organic material determined by the type of the organic matter such as the algal, amorphous, woody and other contents each having a different petroleum potential and the thermal maturity of the kerogen (solid organic substance transforming to hydrocarbons under given subsurface temperature and geologic time) form the factors which govern the oil source capacity of a sedimentary rock (Waples, 1980). It is also mentioned by Waples (1980) that many workers (viz. Hunt, 1972; Welte, 1965 and others) have been concerned with the concentration of organic carbon in source beds and their implication to oil source capacity. Waples (1980), also, stated that according to Hunt (1972) the organic carbon content of an average shale to be around 1% and the quantity factor to have unit (1.0) value.

The maximum thickness of Sirte Shale, with organic carbon content of oil potential exceeding 1%, occurs in the central parts of the troughs (Figure 4). Amorphous variety of kerogen predominates in these parts. Sirte Shale together with the micritic facies of the Tagrifet limestone containing more than 1% of organic carbon is found in the Agedabia Trough with a thickness of about 2500 feet. In the Zella Trough and Marada Trough, the thickness is over 1250 feet. In the Kotla Trough, the thickness is over 1000 feet. The organic carbon content is seen to reach a value of more than 5% within some intervals of the Sirte Shale. Such a section is encountered, for example, in the well 3M1-59 penetrating the depocenter of the Hagfa Trough.

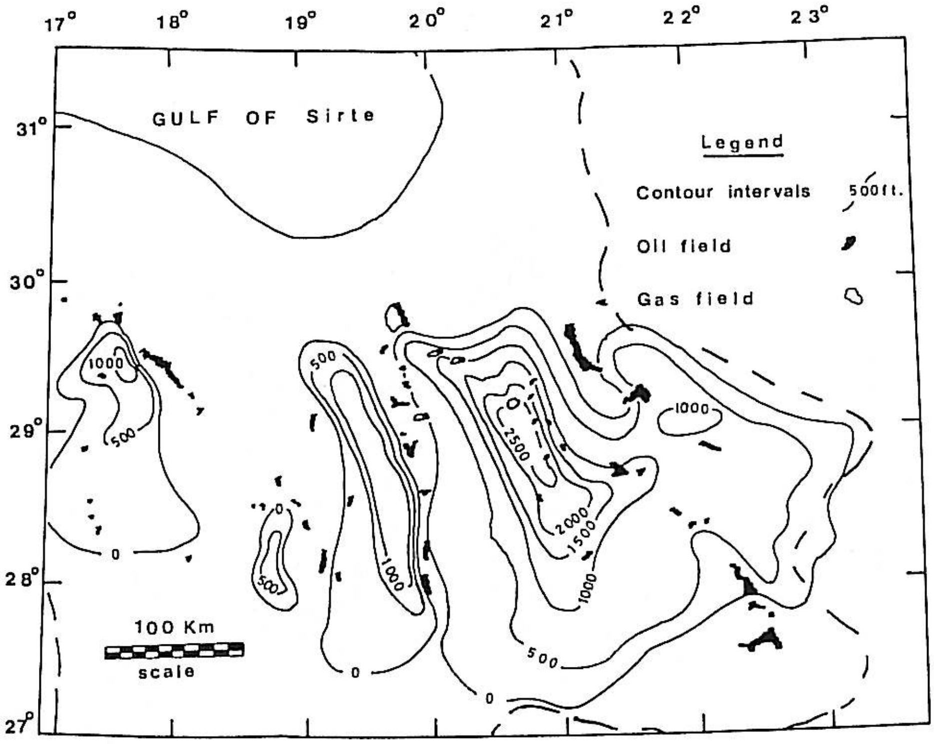

FIG. 4. Thickness of Sirte shale with over 1% organic carbon.

Carbon isotope data for the bulk of the Sirte Shale kerogen samples fall in a broad group with peak alkaline and aromatic hydrocabon fractions of – 29‰ and – 28‰, respectively. These percentages are indicative of strong terrestrial influence in the organic matter accumulations. Also the gas chromatoraph and mass fragmentograph data show relative abundance of steranes and re-arranged sterans to support the above indication. In the basin depocenters located away from the shoreline, however, the triterpanes are relatively more abundant. The carbon isotopes of the kerogene are seen to be slightly heavier to suggest significant algal influence in the constitution of the kerogen. Microscopic study shows that the type of organic matter is almost amorphous and herbaceous and that the algal fractions increase towards the depocenters of the troughs which is consistent with the other indications. The hydrogen index (80 to 480) and the pyrolysis G.C. data, given in table, emphasise the gas-prone to oil-prone gradation the above results invariably show.

Based on the data of pyrolysis G.C. and the type of kerogen as well as on the known geological history of the basin and by extending the organic facies concept of Demaison et al (1983), the distribution of various organic facies of Sirte Shale mapped for the region is presented in Figure 5. The map clearly brings out the non-source facies (type IV) prevalent in the area close to the horsts. The facies is inferred to have been deposited in oxic waters which existed in the shelf flanks as well as in the northern part of the basin. The situation is also characteristic of the western part of the Zella Trough (Tethys Sea). The oxic waters may have resulted from the replenishment of the oxygen under open marine conditions.

The facies is seen to grade from gas-prone (type III) to oil-prone (type II) towards the central part of the graben system. Strongly oil-prone (type I) facies is not found within the Sirte Shale sequence anywhere in the Basin. This feature signifies the possible prevalance of sub-oxic followed by protracted anoxic conditions obtained because of increasing water depths away fom the shoreline. Higher sedimentation rates towards the grabens combined with possible lower influence of terrigineous sources of organic matter may have additionally contributed to the observed situation.

The degree of maturation of kerogen within the Sirte Basin has been estimated as part of the present work from vitrinite refectances and spore coloration data using samples from 88 wells. Figure 6 synthesises the results and shows the presence of six major mature areas in the Basin as far as the Sirte Shale is concerned. These are located in the depocenters of Zella, Marada (Hagfa), Kotla, Agedabia, El-Hameimat (Mar) and Al-Quineen Troughs. The significant levels of oil generation in these areas required burial depths of the order of 10,000 to 11,500 feet. Minor oil generation in the region occured from good quality organic matter in the Sirte Shale and its lateral facies equivalents at depths less than 16000 feet and located between the wells EE 1-6 and AA1-6. Major gas-generation can therefore be anticipated in the corresponding region. Thermal

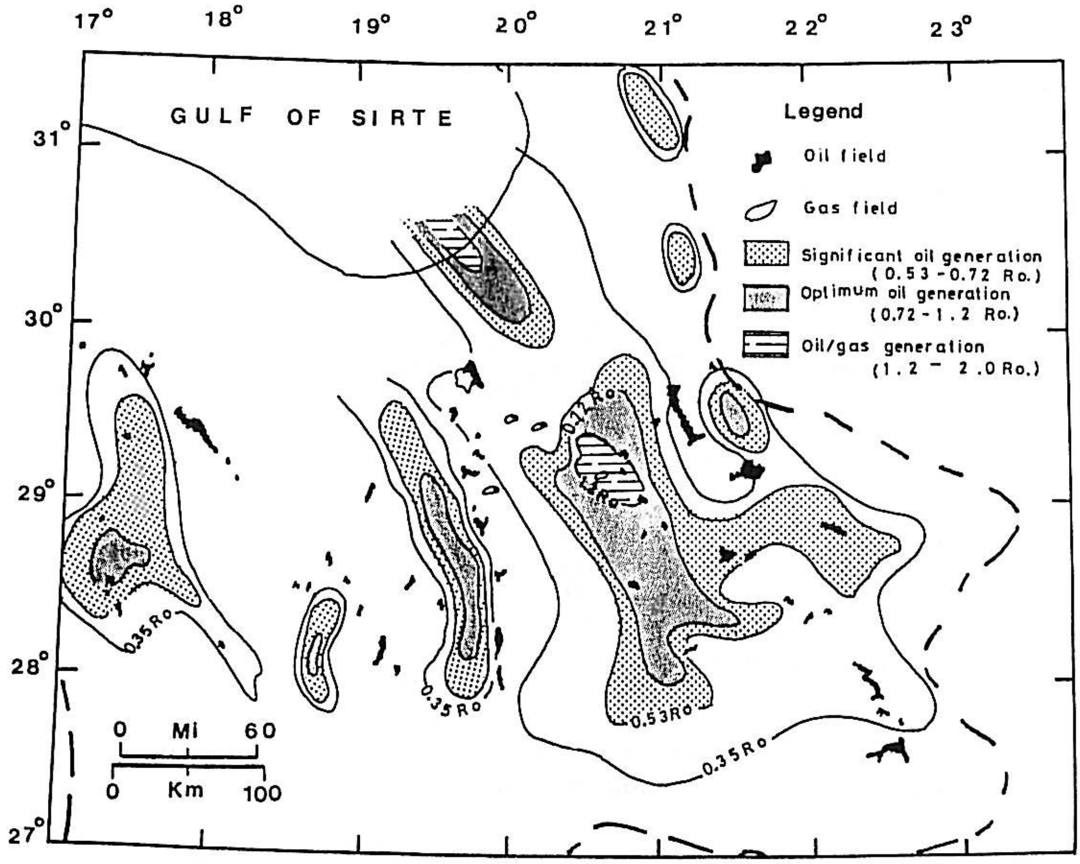

FIG. 5. Distribution of the organic facies, Sirte Shale, Sirte Basin.

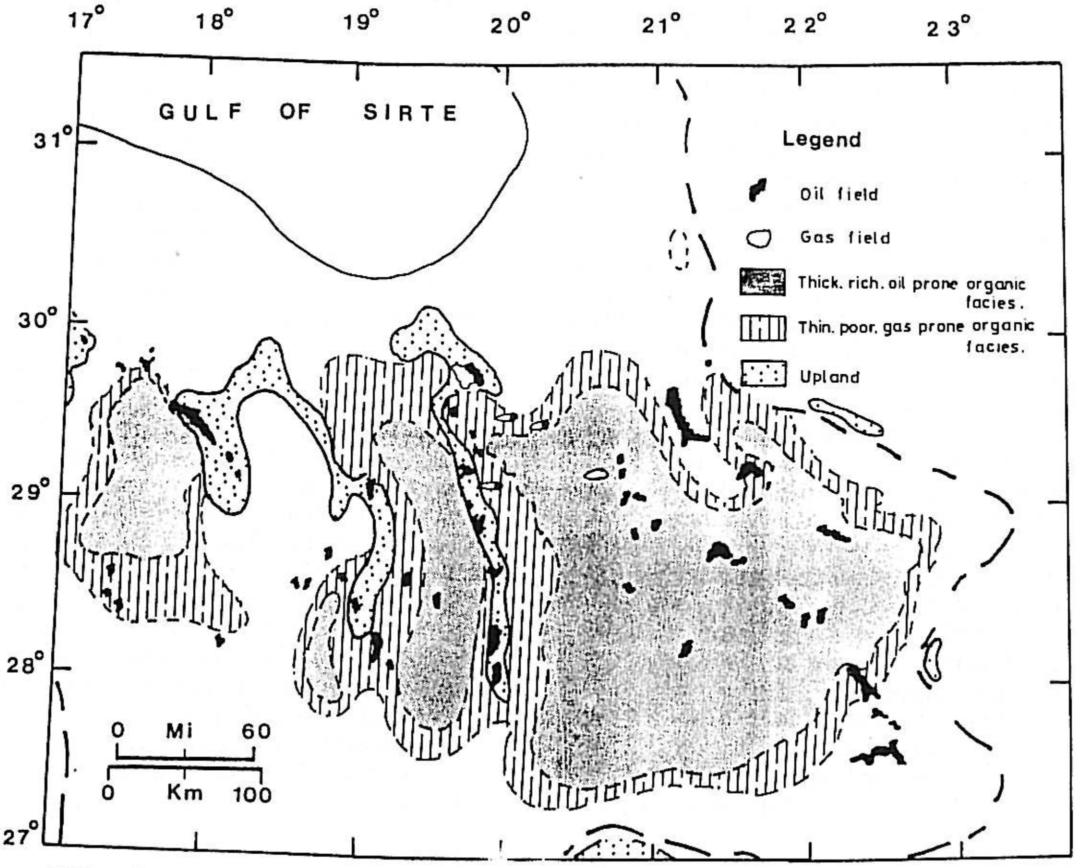

FIG. 6. Thermal maturation levels, Sirte Shale, Sirte Basin.

maturation has also been studied following Lopatin's method of Time Temperature Index (TTI) in assessing the possibility.

The combination of favourable organic facies and maturation levels enabled the demarcation of areas of major oil generation in the Sirte Basin (See Figure 7). The troughs in the Sirte Basin are seen to possess Sirte Shale deposits capable of generating major amounts of oil. In the shelf flank areas and south of approximately the latitude 28°N, however, the shale is characterised by the presence of immature and poor organic facies. The Sirte shale north of latitude 30°N again is likely to be in mature condition in the trough, but impoverished in organic matter to be oil-prone.

OIL TO SOURCE ROCK CORRELATION

A large number of possible source rocks have been identified in the Sirte Basin. Correlation data of 57 crude oil samples to their parent source rock in 88 wells as part of the source rock study attempted involved only the potentially effective source rock for oil.

The carbon isotope data for the bulk of oil samples is summarised in Figure 8. It shows two broad groups with peak values around – 28.5‰and – 27.5‰for parraffin-naphthanes and aromatic hydrocabon fractions, respectively. The carbon isotope of the Sirte Shale Kerogen is slightly less negative compared to

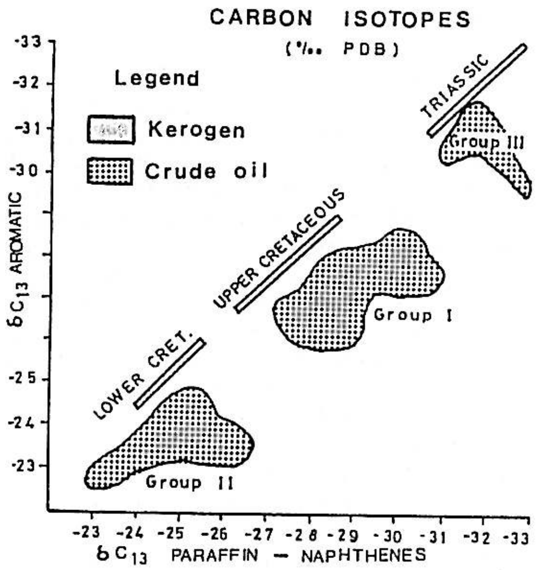

FIG. 8. Oil-source rock correlation based on carbon isotope.

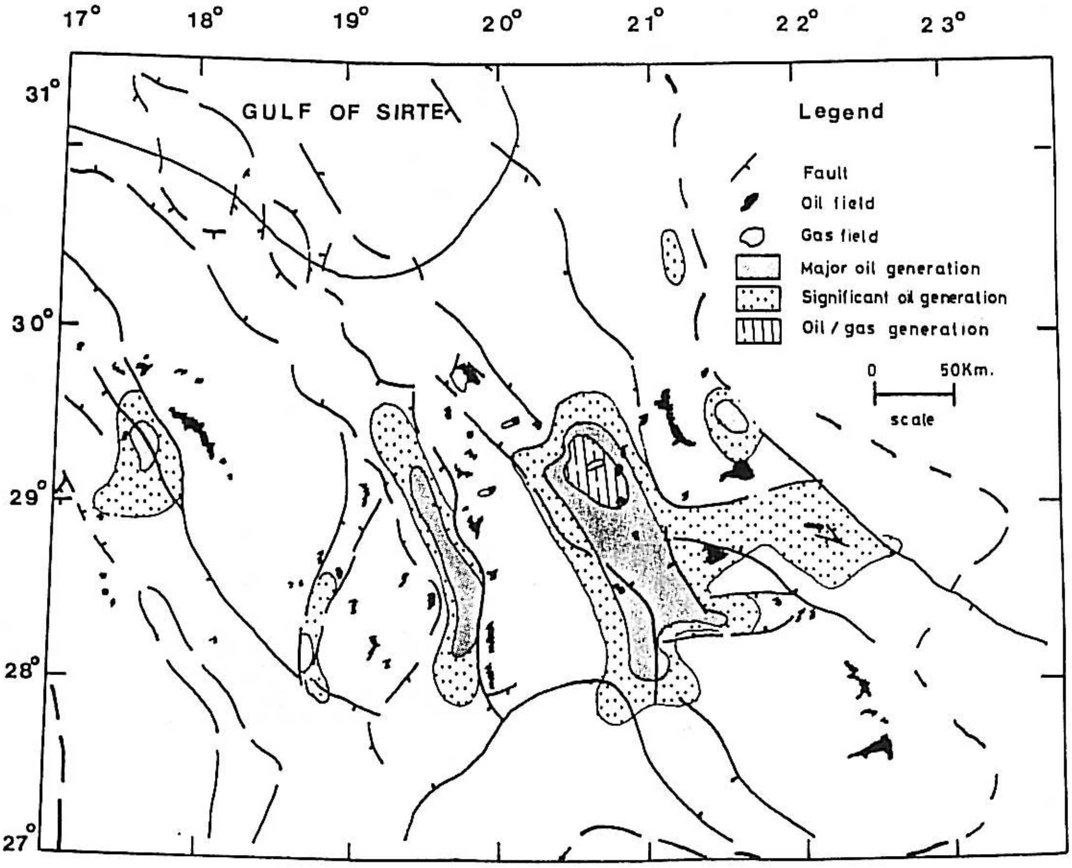

FIG. 7. Areas of major oil generation. Sirte Shale, Sirte Basin.

these peak values which points to terrestrial material input in the organic matter deposited under marine reducing environment. Variations in the carbon isotope fraction is probably associated with changes in the proportion of algal material input which increases towards the depocenters away from the shoreline.

In addition, there are source oils drawn from the southeast of the Sirte Basin which are isotopically heavier (by about – 23 to – 26%) and are distinct in other characteristics as well. The corresponding wells are EE2-59, JJ1-65, SI1-59, Abu Attifel, 0-80 Sarir and UUU 1-59. The crudes from these sites are waxy and appear to have affinity to the lower Cretaceous Shales and/or Etel Evaporites (Torounian Age). These oils of marked heavier isotopic values may have been derived from an algal source with significant terrestrial component and probably deposited in a lagoonal/lacustrine environment.

The oils in the Amal Field are isotopically distinct compared to the other crudes with values around – 31‰.They bear similarity to the source rock which is identified within the Triassic sediments in the well A1-96 near this field. The isotope values indicate association with land plant material deposited in a highly reducing environment.

The polycylic alkane analysis strengthens the results of carbon isotope ratio estimations. The bulk of the oil generated from the Sirte Shale exhibits relative similarity with its source rock judged on the basis of relative abundances of steranes and rearranged storanes. Figure 9 illustrates this feature indicative of land plant material input. The striped triterpanes in the figure points to significant algal component deposited under marine reducing environment. The oils possibly generated from the lower cretaceous shales and/or Etel evaporites are characterised by relative abundance of triterpanes compared to that of steranes and re-arranged steranes. This feature suggests that special species of algal material dominates the organic material that may have been deposited in lagoonal/lacustrine environment with significant terrestrial component input. These oils are also waxy (to about 25%) and have high proportion of C_{20} + normal Paraffins bearing a similarity to the Nubian Shale sediments and/or Etel evaporites.

Sterane and triterpane analysis of oil from F1-31 shows that it is related to the Amal Crude. The crude is distinctly different compared to the first and second groups bearing affinity to Triassic sediments. Also the use of chromatograms to distinguish between crude oils and their parent source rocks point out that there are three groups of oil as forthcomes from Figure 10 derived from three different sources. The corresponding formations are the Upper Cretaceous Sirte Shale, the Lower Cretaceous Nubian Shale and the Triassic Shale.

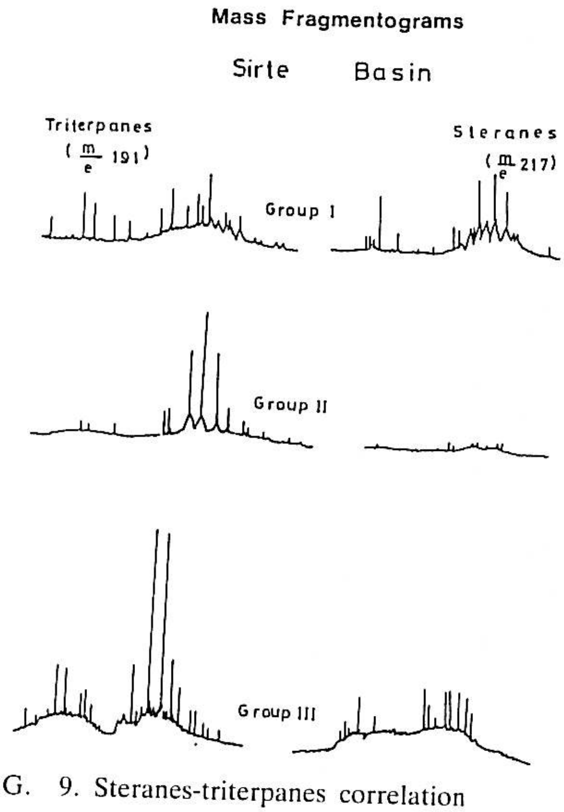

FIG. 9. Steranes-triterpanes correlation of oil groups in Sirte Basin.

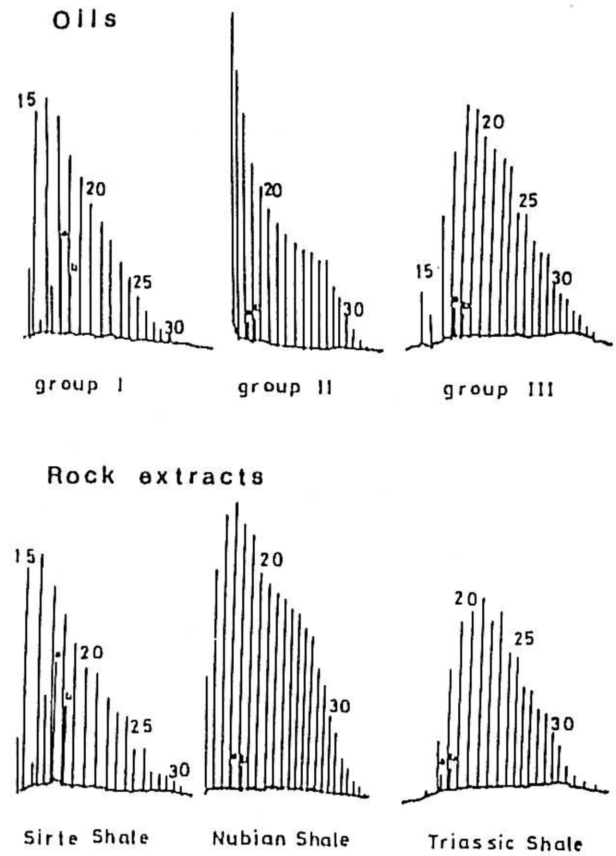

FIG. 10. C_{15} + Paraffin-Naphthenes correlation of oil and rock extrects , Sirte Basin.

Geographic distribution of the oil groups is presented in Figure 11. It shows the relative extensive distribution of the first group with source in the Sirte Shale. The oils from Nubian Shale source rock are limited in occurence to the southeastern Sirte Basin and the oils derived from the Triassic source rock are found only in Amal, F1-31 and A1-96 well sites.

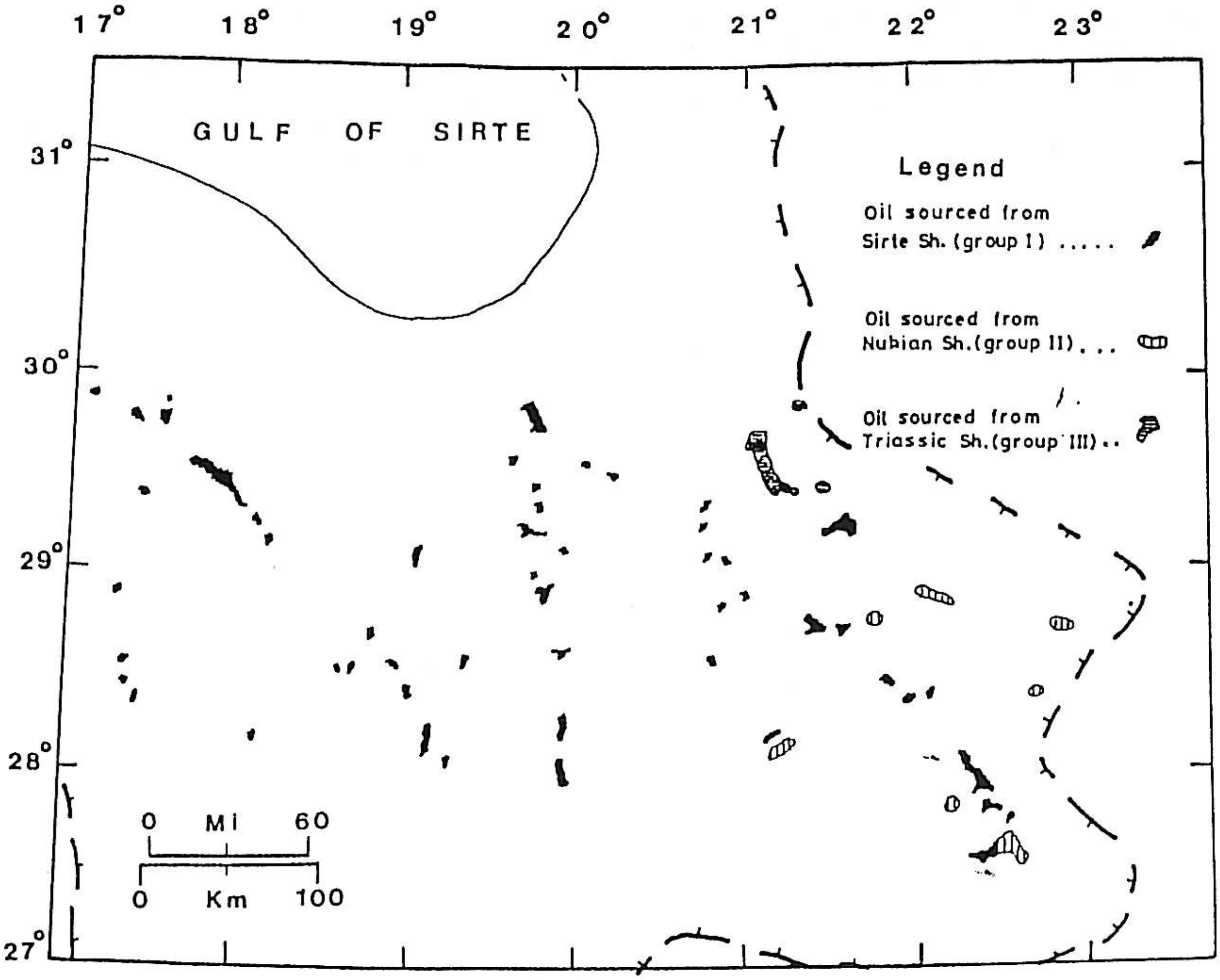

FIG. 11. Distribution of the main three groups of oil in the Basin.

GENERATION AND MIGRATION

The Sirte Shale may be considered as the source rock for the bulk of the oil of the Basin. The type rock of reservoirs varies in lithology from carbonates and sandstone to fractured quartzite and granite dating from Early Cambrian to Oligocene times.

Based on the TTI values from Lopatin's method of analysis attempted on the oil samples of well DD2a-59 (Figure 12), the time of oil generation could be estimated. The well is located in the south central part of the Agedabia Trough. The results indicate oil generation in the Early Miocene. This points out to oil-bearing potential of the Pre-Miocene traps. It is also likely that the Sirte Shale oil source rock may have entered major oil generation stage at a depth below 10 000 feet.

The structural framework of the Sirte Basin consisting of horst-graben system appears to have had a dominant role in controlling the migration routes before entrapment. The migration distances are typically short due to the tectonic style. Vertical faults across porous and permeable beds may have influenced the oil migration paths in the Basin. The migration pattern can be modeled using the present day map of the pre-Upper Cretaceous unconformity. Figure 13 depicts the relation between the Sirte Shale source rock and the possible migration paths to the trap rocks. It is evident that a majority of large oil fields occur on horst blocks adjacent to the generative depressions. A few others appear within the generative depression also.

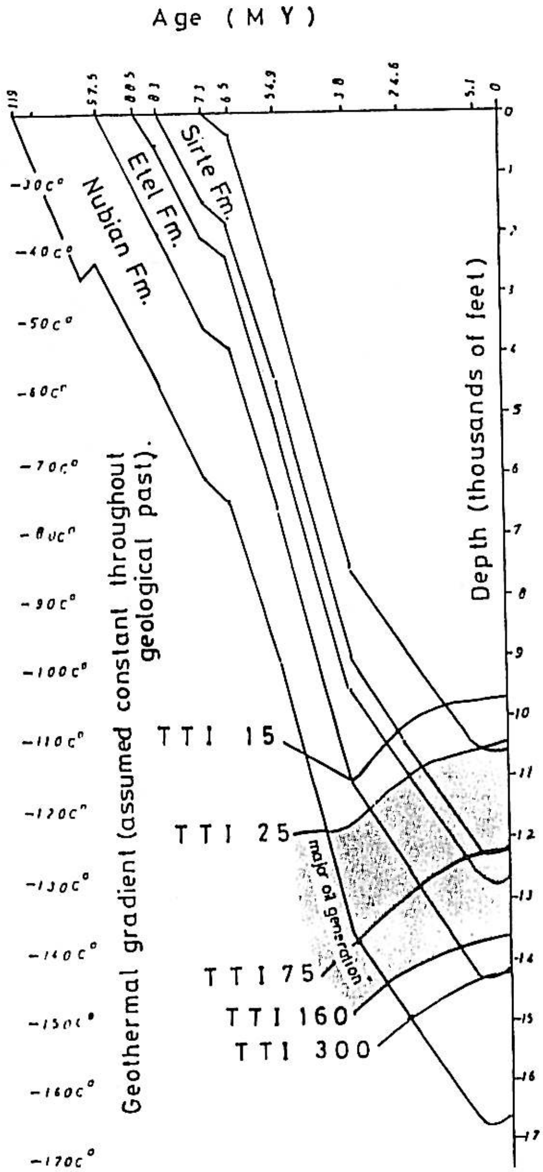

FIG. 12. Iso maturation lines on geologic construction in well DD2a-59, Sirte Basin.

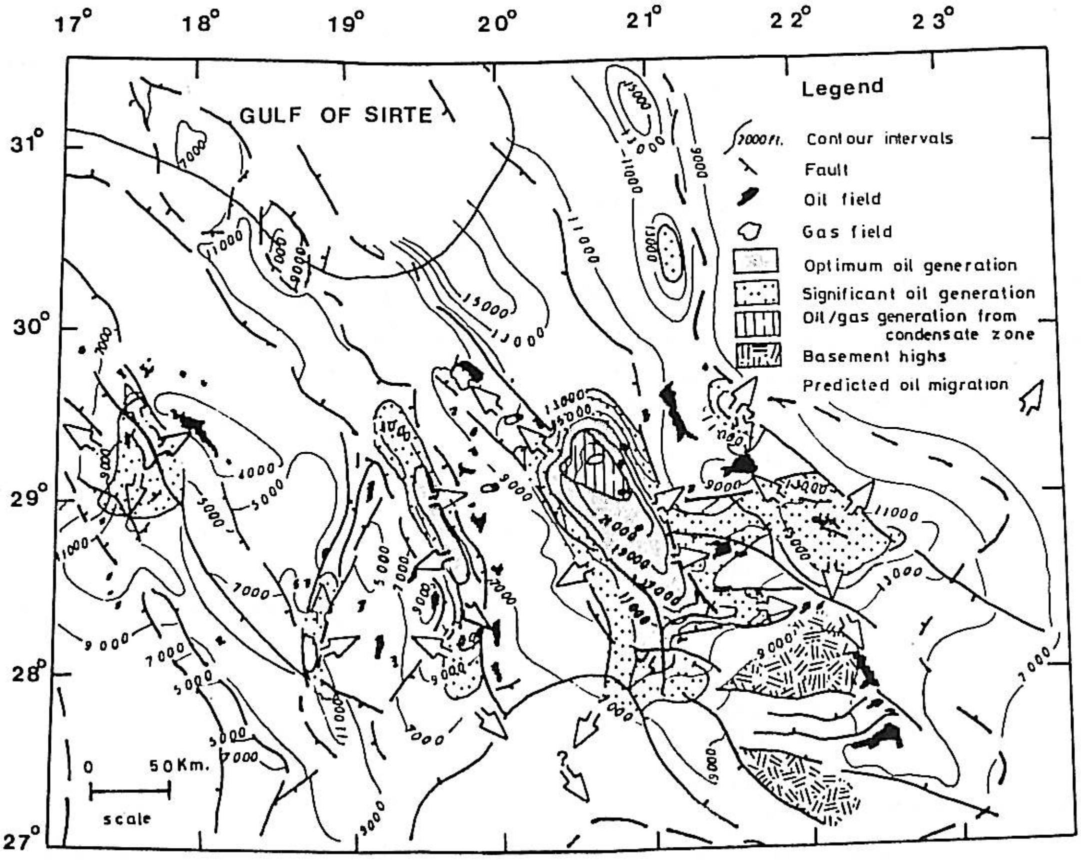

FIG. 13. The postulated migration paths of the oils generated from Sirte Shale.

The available data enables to expect additional effective source rock systems to be present in the sedimentary formations below the Sirte Shale. These may be contributing, at least , part of the oil in the southeastern part of the Basin (as for example in the Attifel Oil field) which are characterised by relatively heavier carbon isotope and excessive wax content. However, the exact positioning of the source rocks for such oils stands difficult. Generally, the lagoonal/ lacustrine environment of algal-dominated source rock may have generated oils rich in the wax content. On the basis of environmental factors it may be mentioned that deposition of the source rock facies may have been fairly frequent during the Turonian and Lower Cretaceous times.

CONCLUSIONS

On the basis of geochemical data and in the light of known geologic history of the Sirte Basin, attempt has been made to provide a stisfactory explanation of source bed genesis, hydrocarbon accumulation and entrapment. The study shows that :

1. Of the Mesozoic- Tertiary sequence, the Sirte Shale (mainly of Campanian age) appears to be the most favourable source rock in containing rich and mature organic facies over a considerable part of the Basin.

2. The Sirte Shale deposited in marine reducing environment abounded in semi-silled grabens during a period of transgression. Its organic facies appear to improve gradually from type IV, III, II-III and II towards the central part of the graben system.

3. The areas of major oil generation could be mapped on a Basin-wide scale. The reservoir rocks close in and on platforms bordering the source-rock accumulations. They are deemed highly prospective areas for hydrocarbon exploration. However, the risk factor increases with distance away from the source pods.

4. The only area with late mature Sirte Shale source rock occurs in the depocenters of the Agedabia Trough (around well AA1-6). It could be a source for the gas accumulations here.

5. The oil generation from Sirte Shale source bed commenced from the Early Miocene and continued till the present time. Against this background it is likely that all traps in the Basin could be hydrocarbon bearing.

6. The tectonic style of the Basin, migration paths and oil-to source rock correlation indicate that the migration distance could be short or moderate.

7. The bulk oil has similarities with the Sirte Shale kerogen. Additional waxy crude contributes a part of the oil in the southeastern part of the Basin such as for example in the Attifel giant oil field. This crude is different from the bulk crudes in terms of all parameters examined in the present work. These waxy oils may have been derived from an algal source perhaps deposited in a lagoonal/lacustrine environment. They may belong to Middle or Lower Cretaceous Sedimentary sequences. Further studies are required to resolve the issue.

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