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Burial history, basin modeling and petroleum source potential in the Western Desert, Egypt

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Abstract— A combination of burial histories, geochemical analyses, Rock-Eval pyrolysis, and types of organic matter have been used to evaluate the potential source rocks and the generation of hydrocarbons in the Western Desert of Egypt. Perhydrous vitrinite and amorphous kerogen appear to be the dominant organic matter with lesser amounts of other maceral components. Good oil prone source rocks have been identified in the Upper Cretaceous while in older sediments mixed and good gas prone source rocks occur. The burial history models indicate that the measured and modeled derived values are in good agreement. The top of the oil window has been interpreted deeper than 8000 ft (Kharita Formation) in both wells studied which indicates that the Middle Jurassic Khatatba Formation, and older sediments, are presently in the late stage of oil generation and are able to generate gas with some oil.
The models suggest the Jurassic Formations began to generate oil during Late Cretaceous. Gas generation is expected during the Eocene and Oligocene in the studied wells. The times of peak oil generation are recorded in the range 87-84 my and at different depths for the studied wells. The Lower Cretaceous Alam El-Beuib sources are expected to generate oil during the Late Cretaceous. But for the Alamein and Kharita Formations, oil was generated during the Miocene. The time of peak oil generation is around 72-71 my for the Alam El-Beuib and 13-12 my for the Alamein and Kharita Formations in the studied wells. In both wells the bottom of gas window is not reached.

Keywords: burial history, thermal maturity, organic geochemistry, source rock, kerogen types

INTRODUCTION

The study area is located in the northern part of the Western Desert of Egypt between latitudes 30° 30' - 31° 00' N and longitudes 26° 30' – 27° 00' E (Figure 1). This area consists of a number of sedimentary basins that received a thick succession of Mesozoic sediments. Various geological studies have been carried out dealing with the stratigraphy, facies distribution, and tectonic framework of these sedimentary basins. The sedimentary section in the northern part of the Western Desert can be divided into three sequences based on lithology, namely: the lower clastic unit from Cambrian to pre-Cenomanian, the middle carbonates from Cenomanian to Eocene and the upper clastic unit from Oligocene to Recent (Said, 1962). The stratigraphic sequence in the northern part of the Western Desert is characterized by a number of major transgressive/regressive cycles on the platform margin. The Mesozoic sequence unconformably overlies Paleozoic rocks. The Mesozoic stratigraphic succession is much better understood than the Paleozoic one as it is encountered in all studied wells, albeit in different thicknesses, as indicated by Abdine and Deibis (1972), Meshref *et al*., (1980), Meshref (1982), Abu El-Naga (1984), Moussa (1986), Barakat *et al*., (1987) and Schlumberger (1984, 1995). Figure 2 illustrates the simplified stratigraphic section in the Western Desert.

The principal objectives of basin analysis are to reconstruct the thermal and burial histories of the basin and to understand the processes and mechanisms by which the basin formed. Moreover, it leads to reconstructing the time evolution of a sedimentary basin in order to make quantitative predictions of geological phenomena leading to oil accumulations. Basin modeling techniques, combined with geochemistry, can be used to tell us about how and when various types of kerogen are converted to hydrocarbons and whether a basin has hydrocarbons in commercial quantities and whether they are likely to be oil, natural gas, or both.

The evaluation of sedimentary rocks as effective source rocks of petroleum requires the determination of the amount and type of organic matter and the degree of conversion of the organic matter to petroleum hydrocarbons. The results provide information about the quantity and quality of organic matter, level of thermal maturity, and source rock potential as discussed by numerous authors such as Barker (1979), Espitalie *et al*., (1985), Leckie *et al*., (1988), Shaheen (1988),

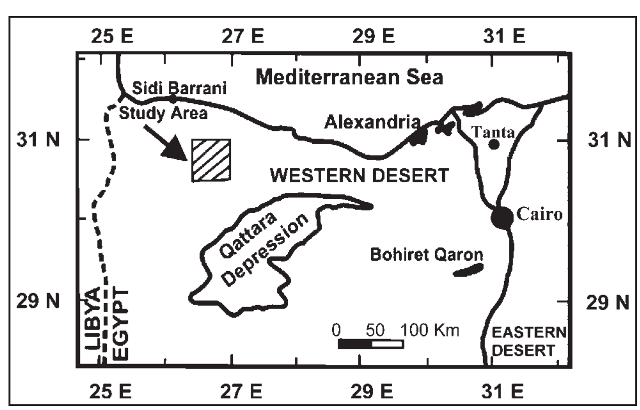


Figure 1: Location map of the study area in the Western Desert, Egypt.

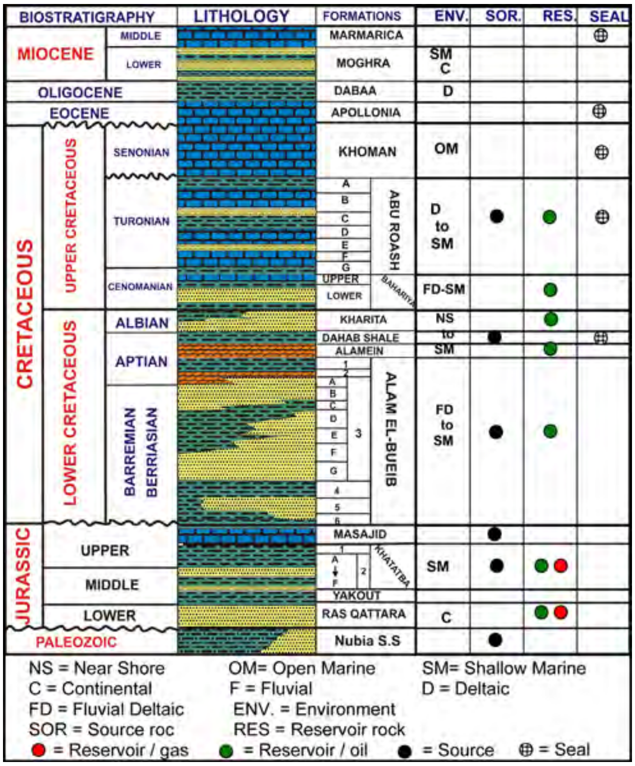


Figure 2: Simplified stratigraphic section of the Western Desert, Egypt (modified after Schlumberger, 1984, 1995).

Waples (1994), Rahman & Kinghorn (1995), Hunt (1996), Pawlewicz & Finn (2002), Sharaf (2003), Roberts *et al*., (2004), Fowler (2004), Shalaby & Abu Shady (2006) and Shaaban *et al*., (2006).

The determination of the thermal maturity of a source rock based on vitrinite reflectance is an important factor for evaluating its hydrocarbon potential. In addition, as shown by Espitalie *et al*. (1977), the temperature of maximum pyrolytic hydrocarbon generation (T_{max}) increases with increased thermal maturity of organic matter. Hence, the T_{max} value is used here to determine the thermal maturity of the investigated samples. Tissot & Welte (1984) reported that the T_{max} value is considered to be among the most reliable factors for characterizing the thermal maturity particularly in the case of marine or lacustrine where vitrinite is often scarce or absent.

METHODS

Burial history, basin modeling and geochemical analyses were carried out to evaluate the hydrocarbon generating potential of source rocks in the Western Desert of Egypt. The analyzed intervals include rocks ranging in age from the Lower Jurassic Ras Qattara Formation to the Cretaceous Abu Roash "F" and "G" Members.

Basin modeling has become an important tool in the study of burial history and thermal evaluation of sedimentary basins and has been used by many authors such as Uysal *et al*., (2000), Rodriguez & Littke (2001), Sheng & Middleton (2002), Ershov *et al*., (2003) and Galushkin *et al*., (2004).

The heat flow history of a basin is proposed by establishing an agreement between a calculated (or modeled) maturity parameters and the equivalent observed maturity parameter (such as vitrinite reflectance). The calculated, or modeled, thermal maturity parameters are usually derived from models that use (1) empirically-based temperature and time integrals (2) the Arrhenius-reaction approach or (3) multiple Arrhenius-reaction models, which attempt to simulate the chemical reactions that produce maturation as indicated by Middleton (1982), Larter (1988) and Wood (1988).

The geochemical analyses, including Rock-Eval pyrolysis and fluorescence microscopy analyses, were carried out on sample sets obtained from the penetrated sections of Shams-2X and Shams-NE Wells. Several cutting and core samples were used from the two wells for geochemical analyses. The composition of kerogen has been studied for a total of 44 samples collected from both wells. These samples were subjected to Rock Eval pyrolysis and microscopic examination to evaluate the composition of organic matter as previously reported by Shalaby and Abu Shady (2006).

Total organic carbon (TOC) is determined in terms of weight percent (wt %) to evaluate the organic richness. A cutoff value of organic richness has been taken as 0.5 wt % TOC (Welte 1965; Tissot & Welte 1978) where all samples with 0.5% TOC or greater were studied by Rock Eval pyrolysis. Several cross-plots have been constructed using the different parameters of geochemical analysis to describe the organic richness and thermal maturity level. Moreover, the study of kerogen type is determined using pyrolysis data by plotting the hydrogen index (HI) versus oxygen index (OI) on a modified Van Krevelen diagram.

The modelling software and calibration of data

The studied wells were modeled using PetroMod 1D modeling software developed by Integrated Exploration System GmbH. Each model was constructed using stratigraphic thicknesses derived from the composite well logs, lithology (combinations of sandstone, shale, limestone) and absolute ages. In the study area, the calibration data for the thermal models includes vitrinite reflectance and the temperature. Modelled vitrinite reflectance (calculated by Easy %Ro (Sweeney & Burnham, 1990)) has been compared to measured data in order to optimize the thermal history model.

RESULTS AND INTERPRETATIONS

Composition of kerogen

The kerogen composition data (provided by an independent service company) as previously published in Shalaby & Abu Shady (2006) has been reclassified here to take into account the presence of contaminated vitrinite and various unstructured organic matter that

Table 1: Composition of organic matter in Shams-2X Well.

FORMATION NAMES	Shams-2X Well	ORGANIC MATTER									
		LIPTINITE				VITRINITE		INERTINITE			
	Sample Depth (ft)	Liptodetrinite	Alginite	Cutinite	Sporinite	Perhydrous Vitrinite	Other Vitrinite	Micrinite	Other Inertinite	Amorphous	Undifferentiated
A	5690-5700	5	5				T		5	85	
	5850-5860	5	5						T	90	
B	6470-6480	10	T		T	20	10		15	45	
D	8580-8590	10	T		T	30	20		10	30	
E	9040-9050	5			T	30	20		10	35	
	9560-9570	5		T		50	T		10	35	
	9980-9990	T		T	T	20	20		10	50	
	10860-10870	T				10	10		10		70
	11160-11170	T			T	60	T		T		40
K	11750-11760	T				10	T		T		90
	11830-11840				T	40	T	50	5		5
	11960-11970	T			T	55	T	40	5		T
	12270-12280					35	10	50	5		T
	12500-12510				T	55	T	40	5		T
	12650-12660					80	T	10	10		
	12730-12740					45	T	50	5		
Y	12810-12820				T	60	T	22	18		T
	12910-12920					42	T		11		47
	12960-12970					42	5	42	11		T
	13030-13040					50	T	40	5		5
R	13200-13210					50	T	45	5		T
	13350-13360	T				53	T	41	6		T

A: Abu Roash Samples B: Bahariya Samples
D: Dahab Samples E: Alam El-Bueib Samples
K: Khatatba Samples Y: Yakout Samples
R: Ras Qattara Samples T: Traces

Table 2: Composition of organic matter in Shams-NE Well.

FORMATION NAMES	Shams-NE Well	ORGANIC MATTER									
		LIPTINITE				VITRINITE		INERTINITE			
	Sample Depth (ft)	Liptodetrinite	Alginite	Cutinite	Sporinite	Perhydrous Vitrinite	Other Vitrinite	Micrinite	Other Inertinite	Amorphous	Undifferentiated
A	5650-5660	5	T			T	T			95	
B	6330-6340	5			T	60	T		15	20	
E	8760-8770	5			T	20	T		15	60	
	9270-9280	5		5	T	70	5		T		15
	9710-9720	5		T	5	52	T		22		16
	11050-11060	7				12	T		18	7	56
K	12040-12050					40	T	50	5		5
	12200-12210					52	T	42	T		6
	12470-12480					55	T	35	5		5
	12520-12530					60	T		5		35
	12570-12580			T		65	T	30	5		T
	12600-12610					70	T	25	5		T
	12630-12640					94		T	6		T
	12640-12650				T	65	T	20	10		5
	12680-12690					95	T		5		T
Y	12720-12730				5	85	T	5	5		T
	12770-12780					90	T		10		T
	12790-12800					85	T	5	10		T
	12810-12820					95		T	5		T
R	13230-13240				T	75	T	20	5		T
	13360-13370				T	65	T	30	5		T
	13430-13440				T	37	T	50	13		T

A: Abu Roash Samples B: Bahariya Samples
D: Dahab Samples E: Alam El-Bueib Samples
K: Khatatba Samples Y: Yakout Samples
R: Ras Qattara Samples T: Traces

were not differentiated in the earlier work. The revised kerogen classificatiobn is shown in Tables 1 and 2. The undifferentiated kerogen consists of a mixture of poorly preserved marine and terrestrially-derived organic matter.

In the Shams-2X Well (Table 1), it is observed that organic matter in most samples is dominated by perhydrous vitrinite which was reported to fluoresce (Shalaby and Abu Shady, 2006). The organic matter is composed of up to 90% amorphous unstructured kerogen, 5% liptodetrinite and 5% alginite, which is typical of marine organic matter.

Small amounts of fluorescent alginite, liptodetrinite and terrigenous sporinite and cutinite occur in some samples, especially in the Alam El-Bueib Formation and shallower formations in both wells.

The composition of organic matter in Shams-NE Well (Table 2) indicates more than 90% amorphous kerogen, about 5% liptodetrinite with trace amount of alginite and vitrinite in the samples of Abu Roash "G" Member. On the other hand, the kerogen composition of the Bahariya Formation appears to be dominated by perhydrous vitrinite (60%) with 20% amorphous organic matter and 5% liptodetrinite.

In both wells, the Alam El-Bueib Formation is generally composed of variable mixed marine and terrigenous organic matter of approximately 7%-60% amorphous organic matter, 12%-70% perhydrous vitrinite, 5-7% liptodetrinite with minor occurrence of cutinite and sporinite.

In the Khatatba and older sediments of both wells, the kerogen is dominated by terrestrial organic matter, approximately 40%-95% of the kerogen being perhydrous vitrinite. The micrinite, which is in high abundance in Khatatba samples and older formations, may represent a disproportionation product that formed as a consequence of hydrocarbon generation as reported by Teichmüller (1974) and Wan Hasiah (1997). It is most apparent that in both wells, the occurrence of micrinite coincides with the disappearance of amorphous organic matter, thus supporting that micrinite is a residual product upon expulsion of hydrocarbons from the amorphous precursor organic matter.

Source rock potential

TOC and Rock Eval data have been used to construct the modified Van Krevelen diagrams as illustrated in Figures 3 & 4, from which three main source rock types have been recognized in both wells. In well Shams-2X (Figure 3), the first type is in the rocks of Abu Roash "F" Member, which appears to be oil-prone containing type-II kerogen (high Hydrogen Index 575 mg HC/g TOC, pyrolysis S2 yields 7.02 mg HC/g rock). The second source rock type which is encountered in the Abu Roash "G" Member is characterized by the ability to generate oil with some gas and is classified as an intermediate type-II/III kerogen. Meanwhile, the third source rock type is predominantly gas-prone with wide distribution throughout the Jurassic section and is classified as containing type-III kerogen.

The HI versus OI plot for the Shams-NE Well (Figure 4) also indicates that three main kerogen types could be identified. The interval 5650-5660 ft of Abu Roash "G" Member contains oil-prone source rocks which have type-II kerogen. Localized intervals of Alam El-Bueib Formation and most of the analyzed rocks from Khatatba and older sediments below 12000 ft are capable of generating mainly gas with some oil. These rocks have kerogen of intermediate type-II/III. The remaining analyzed rocks have poor potential for hydrocarbon generation as they contain type-III kerogen.

The geochemical logs of Shams-2X and Shams-NE Wells are illustrated in Figures 5 & 6 where the different estimated parameters for source rock evaluation have been plotted versus depth for the penetrated section. The penetrated sections in both wells include data collected from Abu Roash Formation represented by "F and G" Members, followed downward by the Bahariya, Kharita, Alam El-Bueib, Khatatba, Yakout and Ras Qattara Formations. TOC values of the different formations range from 0.25-16.79% in Shams-2X Well and from 0.11-53.7% in Shams-NE Well. All samples with 0.5 wt % TOC or more were subjected to further analysis including for pyrolysis T_{max} and vitrinite reflectance. Figures 5 and 6 indicate that some of the plotted points in the shallower interval (Abu Roash, Bahariya and Alam El-Bueib Fms.) were plotted in the zone of low organic carbon while many samples in the deeper part were plotted in the zone of high to very high organic carbon especially samples of Khatatba, Yakout and Ras Qattara Formations.

Fair to very good source potential is expected based on pyrolysis S2 yield of 0.27-28.35 mg HC/g in Shams-2X Well and pyrolysis S2 yield of 0.33-103.9 mg HC/g in Shams-NE Well (Figures 5 and 6). In Shams-2X Well (Figure 5) gas-prone source rocks are generally observed except the Abu Roash Formation which contains primarily good oil-prone source rock. But for Shams-NE Well (Figure 6), it is observed that mixed and oil-prone source rocks have been observed in the upper part of the well (Abu Roash and Bahariya Formations) while the older formations reflect mixed and gas-prone source rock.

The hydrocarbon indications in Shams-2X and Shams-NE wells (Figures 5 and 6) reveal high values (pyrolysis S1 yield 0.11-2.41 mg HC/g) and (pyrolysis S1 yield 0.11-12.6 mg HC/g) and production index (PI) ranges from 0.03-0.56 and 0.04 to 0.33 in both wells, respectively. This may indicate the presence of migrated hydrocarbon. The free (S1) hydrocarbons could have impregnated the vitrinite particles and consequently the vitrinite has acquired a fluorescing perhydrous nature.

Thermal maturity

During the progressive burial history of the area, the source rock is exposed to increasing temperatures. Measured vitrinite reflectance (%Ro) maturities, based on unimodal non-perhydrous vitrinite populations, increase systematically with depth. Based on the maturity profiles (Figure 7) established from the Ro values, it is expected that the top of the oil window (defined by 0.6 %Ro) should be encountered at a depth greater than 8000 ft. Also based on this profile, the Khatatba Formation and older sediments fall

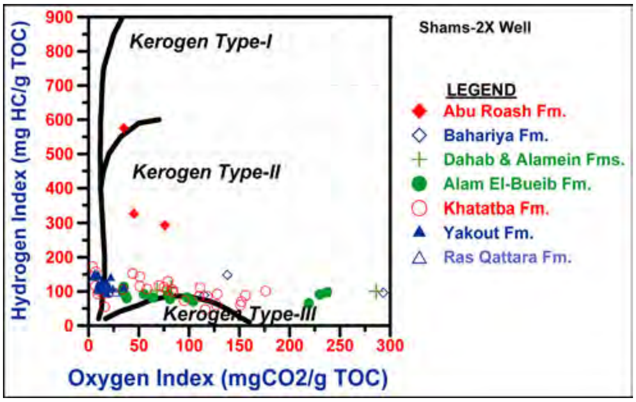


Figure 3: The Kerogen types in Shams-2X Well.

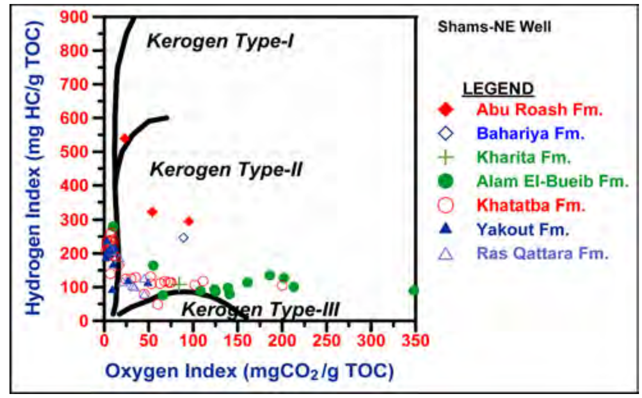


Figure 4: The Kerogen types in Shams-NE Well.

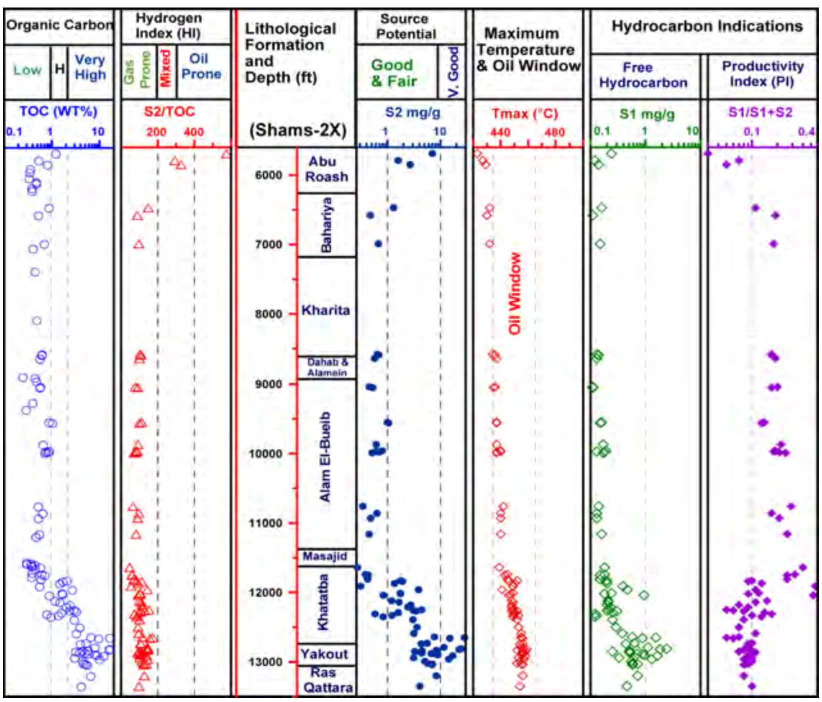


Figure 5: The geochemical log of the Shams-2X Well.

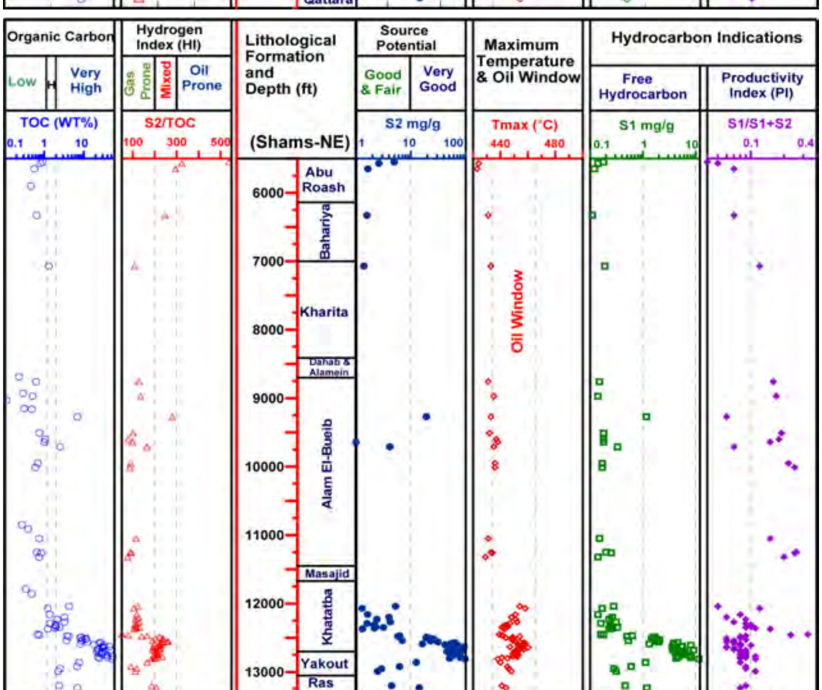
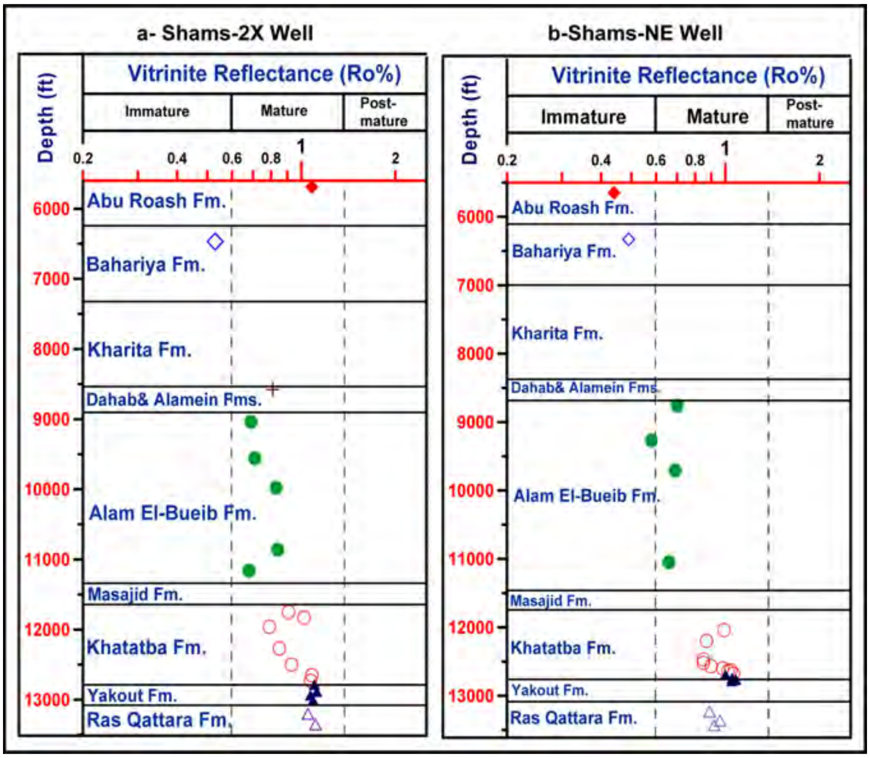
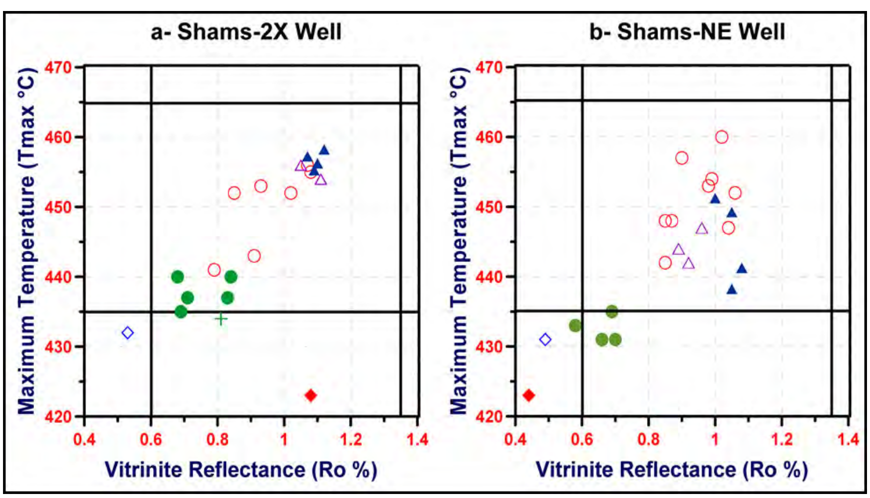


Figure 6: The geochemical log of the Shams-NE Well.



Figures 7: The thermal maturity profiles in Shams-2X and Shams-NE Wells.



Figures 8: A generally good agreement is observed between Tmax and Vitrinite reflectance data in Shams-2X and Shams-NE Wells respectively.

in the late stage of oil generation and at top of gas window (about 1.25 % Ro).

Figures 8a & b reveal that most of the plotted data are located in the oil window zone defined by T_{max} (435-465 ºC) and vitrinite reflectance values of (0.6-1.35 Ro%). Generally, the beginning of the oil window occurs at a T_{max} value of approximately 435ºC which indicates mature organic matter, while the end of oil generation (beginning of wet gas and condensate) is indicated by T_{max} values of approximately more than 450ºC. In this study, pyrolysis T_{max} values are in the range of 417ºC-460ºC representing good possibility for hydrocarbon generation where the rocks enter the oil window through to gas window in both wells.

Note that in Shams-2X Well (Table 1), the occurrence of amorphous organic matter down to 10000 ft, whereas micrinitized kerogen (i.e. residual product at the end of oil generation) occurs deeper than 11800 ft. Thus thermal maturity appears to be in accordance with kerogen composition data suggesting that Khatatba and older sediments are already within and towards the end of oil window.

In the Shams-NE Well (Table 2), it was also observed that the amorphous organic matter occurs, albeit at slightly deeper depth that is down to 11060 ft, and becomes micrinitized deeper than 12000 ft. The expelled hydrocarbons will have impregnated the source rock and the vitrinite causing it to fluoresce and consequently shows the perhydrous character.

Burial history and basin modelling

Figures 9 to 12 show the burial history and thermal maturity for both wells. The subsidence during the Jurassic

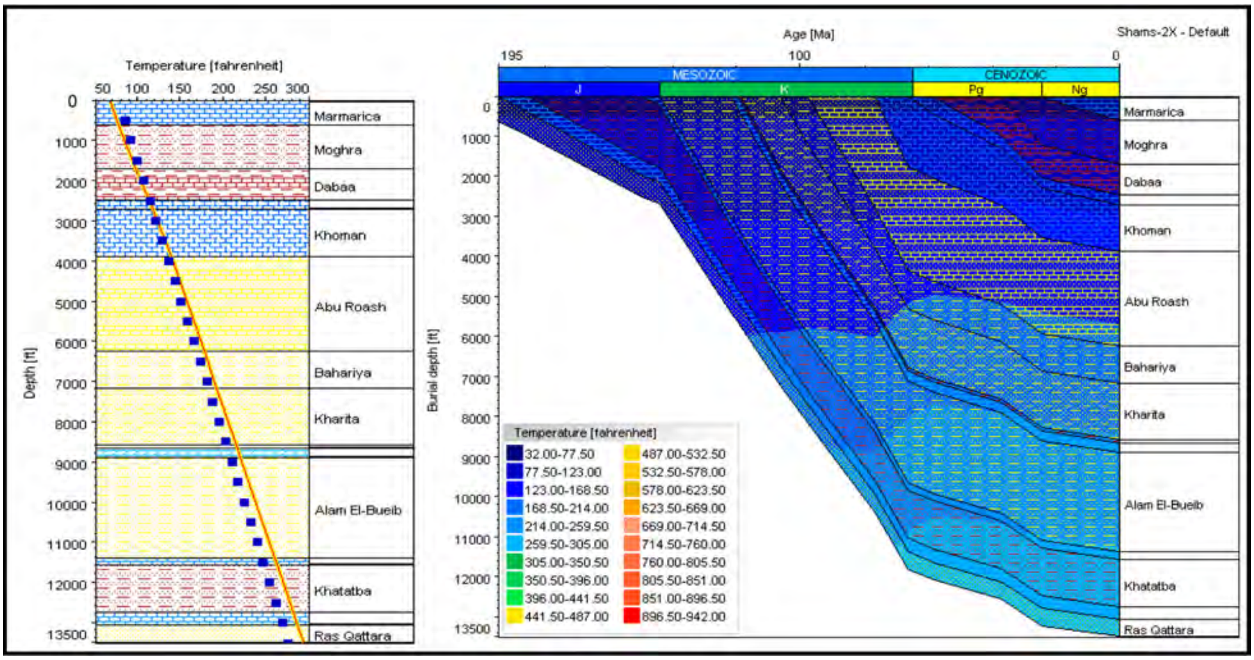


Figure 9: Thermal burial history and temperature fitting in Shams-2X Well.

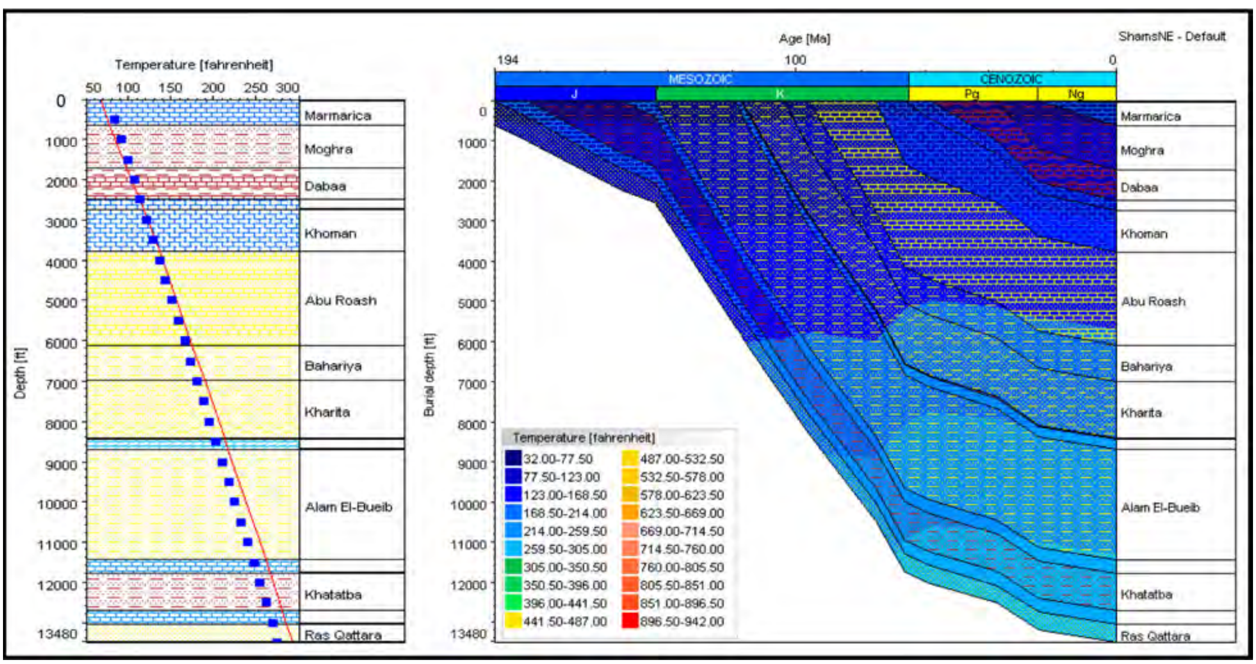


Figure 10: Thermal burial history and temperature fitting in Shams-NE Well.

period (208–144 my) was characterized by low burial rates of about 32 ft per million years. The Jurassic succession deposited during this period is now about 2119 ft thick. Following this phase, subsidence increased to about 108 ft per million years during Lower Cretaceous (144–104 my) where the total thickness of sediment deposited is now 4212 ft. During the Late Cretaceous (104–66 my) high burial rates of approximately 114 ft per million years resulting in a present day thickness of about 4443 ft. From the end of Cretaceous to recent the depression reached its maximum burial depth in the studied wells (13500 ft). This period of subsidence was characterized by a distinct decrease in subsidence rate. The maximum present day thickness is 2724 ft and the burial rate of deposition was about 41 ft per million years.

1-D PetroMod software has been used for constructing the thermal and burial history models and locating the oil window for each well. The timing of hydrocarbon generation may be determined by applying appropriate kinetic parameters to the kerogen. The models for both wells indicate that the depth of the oil window and the timing of oil and gas generation are quite similar.

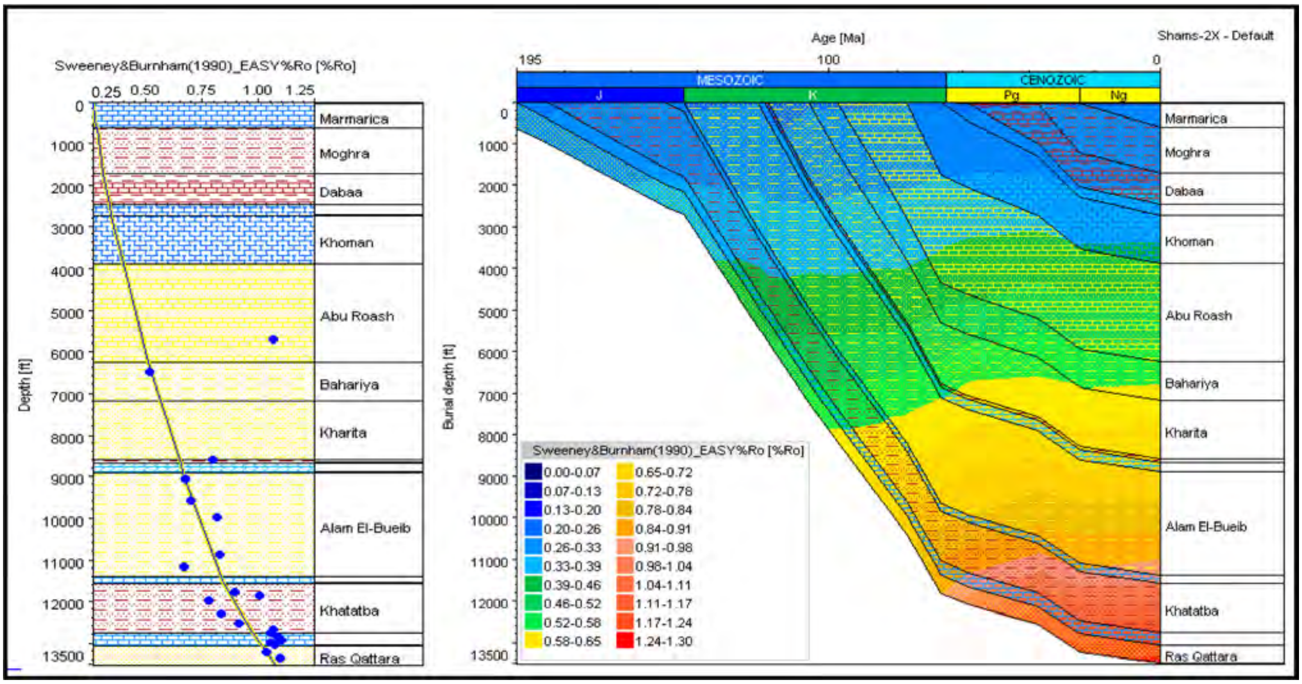


Figure 11: The burial history and maturity levels in Shams-2X Well.

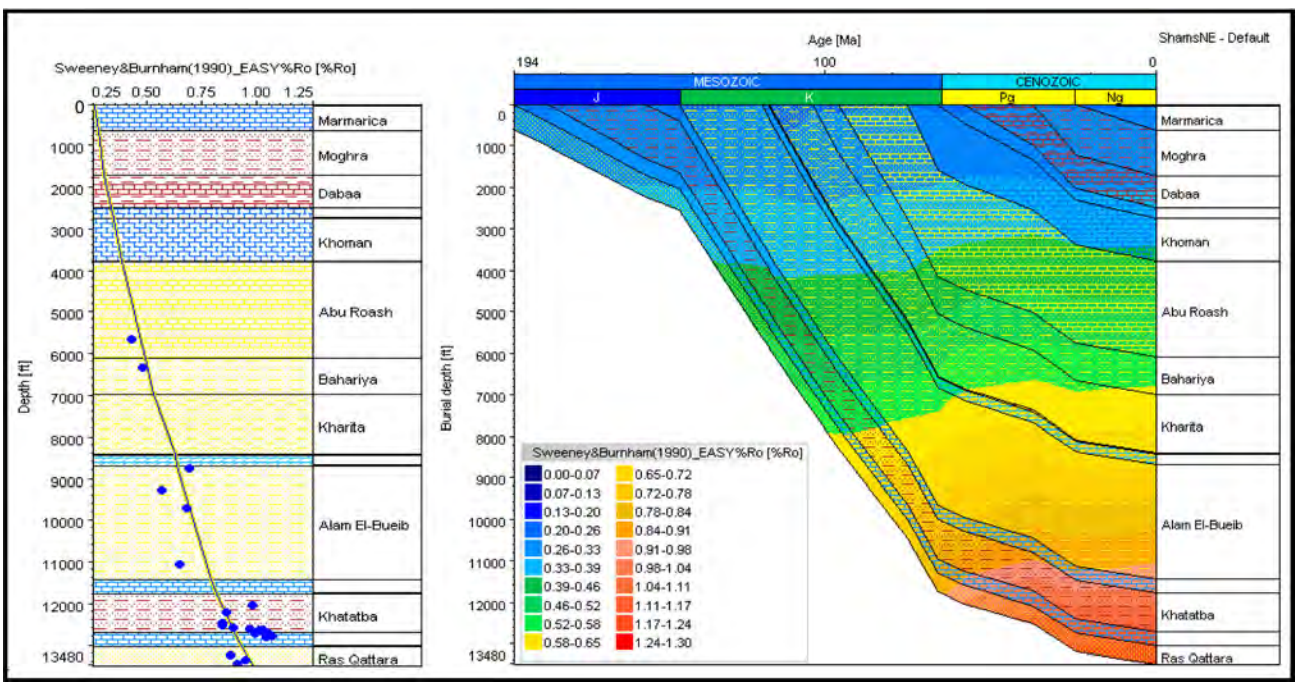


Figure 12: The burial history and maturity levels in Shams-NE Well.

A geothermal gradient and vitrinite reflectance data from the studied wells were available for calibration. Thermal calibration can be done by comparing the computed temperatures to the measured geothermal gradients and adjusting heat flow until a reasonable fit is reached. Figures 9 and 10 show the temperature fitting and the thermal burial histories of the studied wells. It is observed that a good fit of temperature data are observed in both wells where the computed temperature and geothermal gradient derived temperature data are approximately coincident to each others. This suggests that the constructed thermal burial histories are good and reasonable.

Figures 11 and 12 show the relationship between measured and modeled vitrinite reflectance values, which indicate good agreement and suggest the models which represent the studied basin are approximately true and accurate. It is expected that the source rock reach the top of the oil window (the zone where petroleum is generated) deeper than 8000 ft as indicated by vitrinite reflectance of approximately 0.6% Ro.

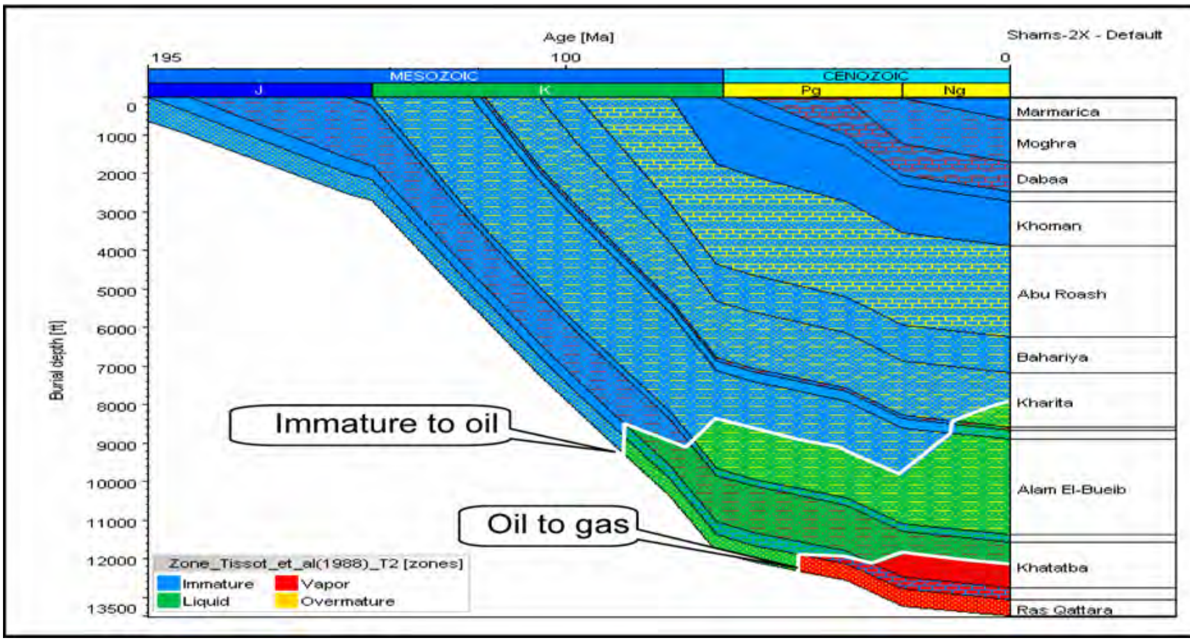


Figure 13: The burial history and hydrocarbon generation in Shams-2X Well.

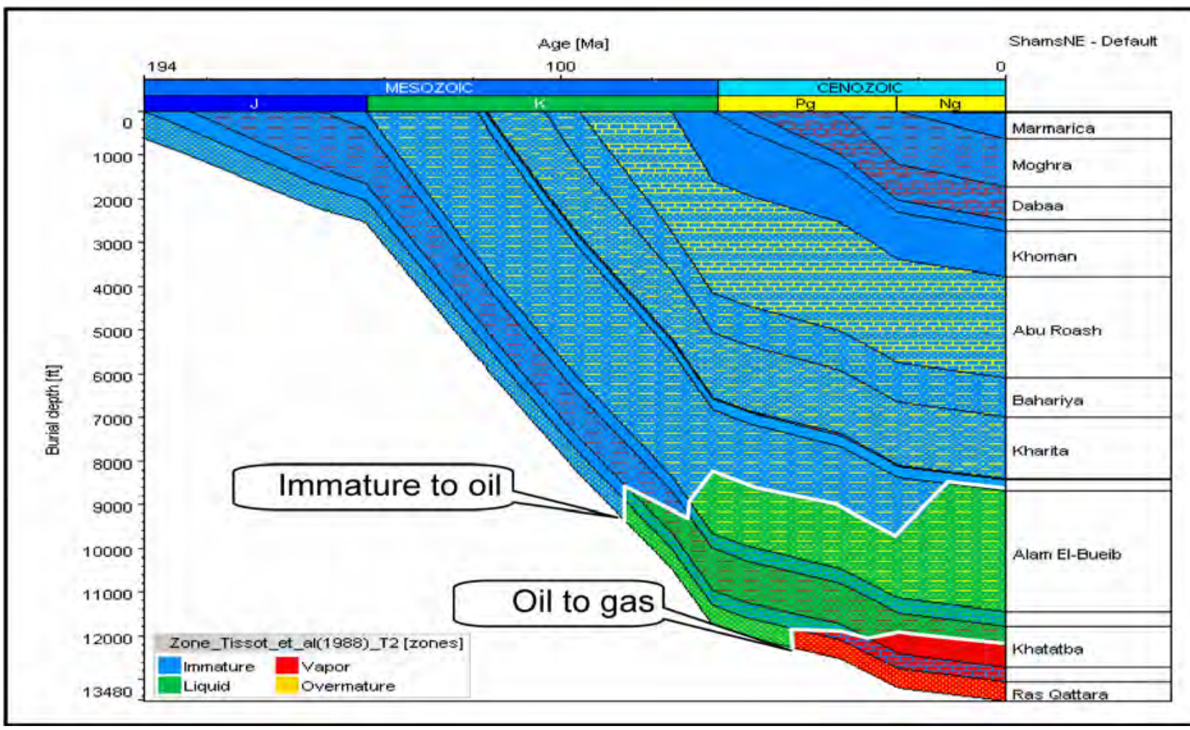


Figure 14: The burial history and hydrocarbon generation in Shams-NE Well.

Table 3: Age, depth of top oil and gas generation in the Shams-2X Well.

AGE	FORMATION	Time (my) /depth (ft) of top of oil generation	Time (my) / depth (ft) of top of gas generation
JURASSIC	RAS QATTARA	87 / 9272	47 / 12316
	KHATATBA	86 / 8511	30 / 12119
LOWER CRETACEOUS	ALAM EL-BUEIB	72 / 8934	-
	ALAMEIN	13 / 8737	-
	KHARITA	12 / 8399	-

Table 4: Age, depth of top oil and gas generation in the Shams-NE Well.

AGE	FORMATION	Time (my) / depth (ft) of top of oil generation	Time (my) / depth (ft) of top of gas generation
JURASSIC	RAS QATTARA	85 / 9376	46 / 12270
	KHATATBA	84 / 8555	29 / 12045
LOWER CRETACEOUS	ALAM EL-BUEIB	71 / 8977	-
	ALAMEIN	12 / 8527	-
	KHARITA	-	-

The burial history diagrams (Figures 13 and 14) are superposed with gas and oil window limits for both wells. The total drilled depth of the Shams-2X Well is 13500 ft, and 13480 ft in Shams-NE Well. The Jurassic Ras Qattara and Khatatba Formations are expected to generate oil during deposition of the Late Cretaceous Abu Roash Formation. In the Shams-2X Well, the time of beginning of oil generation for the Jurassic Ras Qattara was 87 my and for the Khatatba Formations it was 86 my. The top of oil window (figure 13) is about 9272 ft for the Ras Qattara and 8511 ft for the Khatatba Formation (Table 3). In the Shams-NE Well (figure 14), it is observed that the time of beginning of oil generation was at 85 my and 84 my for the Ras Qattara and Khatatba Formations, respectively, which occurred at 9376 ft for the Ras Qattara and at 8555 ft for the Khatatba (Table 4).

The oil generation in the Lower Cretaceous Alam El-Bueib sources is expected to begin during deposition of the Late Cretaceous Khoman Fomation. This occurred between 72 my and 71 my with depth to top of oil window at 8934ft and 8977 ft in the Shams-2X and Shams-NE Wells, respectively (Figures 13 & 14). The Lower Cretaceous Alamein and Kharita Formations are expected to generate oil during deposition of the Miocene Marmarica Formation. In Shams-2X Well (Figure 13), the peak of oil generation is expected to be at time 13 my and at a depth of around 8737 ft for the Alamein Fm while it was at 12 my and at depth of 8399 ft for the Kharita Formation (Table 3). In the Shams-NE Well (Figure 14), the Alamein Formation reached peak generation at 12 my at a depth of 8527 ft (Table 4).

Gas generation is expected from the Jurassic Ras Qattara Formation during deposition of the Eocene Dabaa Formation in the investigated wells. The gas window was entered at approximately 47-46 my and it is expected to be at depths 12316 ft and 12270 ft in the Shams-2X and Shams-NE Wells, respectively (Figures 13 & 14). The Jurassic Khatatba Formation generated gas during deposition of the Oligocene Moghra Formation in both wells. The gas generation started at 30 and 29 my at depths 12119 ft and 12045 ft in the Shams-2X and Shams-NE Wells, respectively (Figures 13 & 14). In both wells, the bottom of the gas window is not reached by the total depth of the wells (Tables 3 and 4).

CONCLUSIONS

The organic matter in all samples is composed primarily of unstructured amorphous kerogen and perhydrous vitrinite. Small amounts of alginite, liptodetrinite, cutinite and sporinite occur in some samples, especially in the Alam El-Bueib Fm and younger formations. The analyzed rocks in the older formations (Khatatba, Yakout and Ras Qattara) are lacking in liptodetrinite, alginite and amorphous organic matter, and contain predominantly perhydrous vitrinite and micrinite with variable amount of undifferentiated (mixed marine and terrigenous) organic matter. This may indicate that primarily gas rather than oil would be generated in these older source intervals.

In the analyzed sections of both Shams-2X and Shams-NE Wells, good oil-prone source rocks occur particularly in the younger formations. The Khatatba and older sediments are characterized by mixed and good gas-prone source rock potential which are able to generate mainly gas with some oil. The total thickness of gas-prone source beds in well Shams-2X is 350 ft. The thermal maturity indices, Rock-Eval pyrolysis data and the constructed burial histories and basin models suggest that the top of the oil window (defined by Ro 0.6%) should be encountered at approximately 8000 ft. The increasing maturity level deeper than 11800 ft of the Khatatba and older sediments reflects that it is in the late stages of oil generation and is at the top of gas generation maturity, while the Ras Qattara is already in gas window.

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