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Modelling Petroleum Generation within the Upper Cretaceous–Tertiary of the Ajdābiyā Trough, NE Sirt Basin, Libya

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ABSTRACT

The oil productive Upper Cretaceous–Tertiary succession of NE Sirt Basin with many potential source rocks and reservoirs is an important future petroleum exploration target within the deepest Ajdābiyā Trough of Libya. The modelling of petroleum generation within the succession and related time and area of oil generation is reconstructed from the geothermal history of 21 wells including 7 wells with geochemical data on TOC and Rock-Eval pyrolysis, whereas the present-day geothermal gradient is based on 31 wells within the study area.

The best source rocks of the area are organic-rich shales of the Upper Cretaceous Sirt Formation (Rakb Group), which are fully mature in most of the study area, and could have generated significant quantities of oil and gas since the Eocene. The next best source rocks are comparatively thin shaly units of the Palaeocene and Eocene, which are thermally mature towards the SW deeper parts of the trough and may be generating oil currently. The origin of the small accumulation in B1-40 and oil shows in various wells within the Palaeocene and Eocene is uncertain and requires detailed oil-source correlation studies.

The average present-day geothermal gradient is 3.1°C/100 m with a higher gradient trend towards the deeper parts. The oil-generative window lies between 2500 and 4000 m with the peak oil generation zone below 3000 m.

INTRODUCTION

The Mesozoic–Tertiary succession of Libya is an important world petroleum province that contains most of the Libyan recoverable reserves and demonstrates high potential for further oil discoveries. Total reserves for Libya have been estimated variously at 23 billion barrels of oil (Futyan and Jawzi, 1996), over 50 billion barrels of oil and 40 trillion cubic feet of gas (Rusk, 2001), and 35 billion barrels of oil and 46.5 trillion cubic feet of gas (Sullivan, 2003). The oil-prone Mesozoic–Tertiary Sirt Basin has recoverable reserves of 45 billion barrels of oil and 33 trillion cubic feet of gas in 250 fields, which include 18 of the 21 giant fields in Libya (Rusk, 2001). According to Ahlbrandt (2001) known reserves of the Sirt Basin are 43.1 billion barrels of oil equivalent. The Upper Cretaceous–Tertiary petroleum system yield was high, estimated as 1090 billion barrels of oil equivalent (boe) generated, of which 120 billion barrels of boe are of stock tank original oil in place (STOIP) with a yield of 11.01% (Biteau and Perrodon, 2003a, b). So far, only 30% of the total Libyan area has been explored and most of the reserves were discovered before 1970 in comparatively straightforward and shallow plays indicating a vast potential for further discoveries within the underexplored part of the Ajdābiyā Trough, the Marādah Graben, and the Zallah-Tumayam Trough (Rusk, 2001).

This study presents the hydrocarbon generation history of the NE part of the Ajdābiyā Trough, which is comparatively longer, wider and deeper than other troughs. The aims are firstly, to identify and characterize the source-rock intervals from the first-hand geochemical analyses carried out by the Geochemical Laboratory of the Arabian Gulf Oil Company (AGOCO). Secondly, to develop one-dimensional geologically plausible maturity models of key wells by combining measured maturity values and present-day formation temperatures with burial, erosional, and thermal information. Thirdly, the maturity models are used to develop two-dimensional models of the geological cross sections so as to reconstruct the process of hydrocarbon generation as a function of the type and amount of kerogen as inferred from the geochemical data. Finally, to estimate the charge timing of petroleum systems from recognized source rock within the study area of the Ajdābiyā Trough.

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PETROLEUM GEOLOGY

The Sirt is the youngest oil productive basin in Libya and one of the most oil-prolific rifted basins in the world, and consists mainly of a NW-SE trending horst-and-graben system with over 7500 m of thick Cretaceous–Tertiary graben-fill. The major substructures trend NW-SE in the north, N-S in the south and E-W in the east (Fig. 1). The development of the horst-and-graben system began in the Cretaceous with deposition of major reservoirs on horst blocks and main source rocks within the grabens.

A study on petroleum generation modelling within the Upper Cretaceous-Tertiary successions is presented below, with an emphasis on the stratigraphy of the NE Sirt Basin. The geological and stratigraphic information is from various unpublished reports and published papers including Conant and Goudarzi (1967), Sanford (1970), Barr and Weegar (1972), Goudarzi (1980), Lewis (1990), Klemme and Ulmishek (1991), Ibrahim (1991), Ambrose (2000), Ahlbrandt (2001), Rusk (2001), and Hallett (2002).

Pre–Upper Cretaceous Successions

The Cambrian-Ordovician sandy facies (Hofra Formation) present within and along the periphery of the Sirt Basin are remnants of the early Palaeozoic passive margin-sag stage and pre-date the formation of Sirt Basin. It is productive at the Zalṭan-Al Wahāh High (Barr and Weegar, 1972; Ibrahim, 1991).

The thick pre–Cenomanian continental to marginal marine sandy facies (Sarir, Amal or Nubian Sandstone) was deposited over the basement and Palaeozoic rocks as a result of rifting which commenced in the Early Cretaceous and before the main phase of rifting and development of the Sirt Basin. The sandstones are the major oil producer (Sarir C, Messla, UU1-65, Kalanshiyu, Āmāl fields), and the lacustrine to marginal marine shaly facies (Variegated Shale) provide source and seal rocks within the eastern Sirt Basin (Barr and Weegar, 1972); Ibrahim, 1991; El-Alami, 1996; Ambrose, 2000). This succession is not a part of this study.

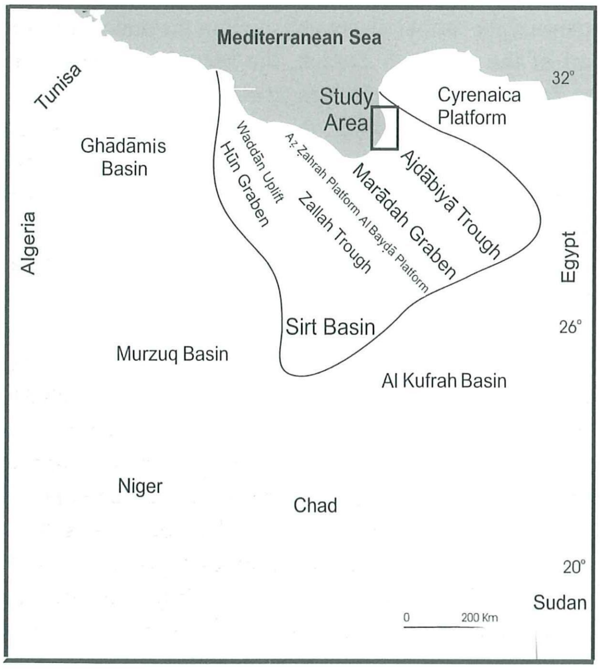

Fig. 1. Location of Sirt Basin, major structural units, and study area.

Upper Cretaceous–Tertiary Successions

The main phase of rifting and the formation of Sirt Basin began in the Albian or early Cenomanian as a result of extensional and probably transtensional faulting and deformation of the Sirt-Tībistī arch, which resulted in five major grabens (Hūn, Zallah, Marādah, Ajdābiyā, and Ḥameimāt), separated by four major platforms (Waddān, Aẓ Ẓahrah-Al Bayḍā, Zalṭan, and Āmāl-Jālū). Thick shale and subordinate carbonate and evaporites of the Upper Cretaceous–Tertiary succession unconformably (Sirt unconformity) overlie the pre–Cenomanian siliciclastics in grabens and half grabens. On the platform, however, a considerably reduced thickness of dominantly shallow marine carbonates was deposited, where they have depositional or fault contact with the basement or Cambrian–Ordovician rocks. The Palaeocene–Eocene successions show less thickness variation between graben and platform due to reduced rift tectonics, whereas the Oligocene–Pliocene successions were deposited in an interior sag environment, with a gradual eastward shift of the sag axis.

Upper Cretaceous

In the eastern Sirt Basin, deposition began in the Cenomanian and deposited the predominantly marine sandy facies of the Maragh Formation (oil reservoir) which unconformably overlie the pre–Cenomanian successions (Sarir Sandstone, Amal Formation, volcanic, or granite rocks). These in turn are overlain by the carbonate facies of the Lidam Formation (oil reservoir). The Rakb Group overlies the Lidam Formation which includes the evaporitic, dolomitic, and shaly facies of the Etel Formation, the predominantly shaly facies of the Rachmat Formation, the shallow marine carbonates of the Taqrifat Limestone (oil reservoir), and finally the calcareous shaly facies of the Sirt Formation. The organic-rich dark grey, waxy shales of the Sirt Formation are the principal source rocks of the basin. Towards the close of the Cretaceous, the deposition of carbonate facies re-commenced and the dense micritic limestone sequence of the Kalash Formation was deposited. The Taqrifat and Waha limestones are the principal reservoir in Awjilah, An Nāfūrah, and Al Wāḥah fields (Barr and Weegar, 1972).

Palaeocene–Eocene

Deposition of carbonate and shaly facies continued with major carbonate (reefal) build-ups over horst blocks that form some of the best reservoirs in the basin and shaly facies which were deposited within grabens. Deposition began with the deep shaly to shallow marine carbonate facies of the Al Hagfah Formation . This was followed by the carbonate facies of the Al Bayda Formation – oil reservoir (Sabil Carbonates). Towards the close of the Palaeocene and the beginning of Eocene the deposition of shaly facies predominate (Khalifah Formation) and this is successively followed by carbonate facies (Zaltan Formation), shale and limestone facies (Harash Formation) and finally shaly facies (Khayir/ Kheir Formation). The deposition of shaly and carbonate facies continued during the Eocene with deposition of Al Jir (Gir) Formation which is comprised of dolomitic Facha – oil reservoir, evaporitic Hun – seal, and massive carbonate Mesdar members. The overlying Jalu (Gialo) Formation – oil reservoir, is followed by the shaly and carbonate facies of the Awjilah (Augila) Formation, and its limited distribution Rashda Member which is an oil reservoir.

Oligocene–Miocene

Deposition of predominantly clastic facies recommenced; the basal sandy facies of the Oligocene (Arida Formation) unconformably overlie the carbonate facies of the Eocene (Awjilah Formation). The deposition of clastics facies continued (Diba and Marada formations) followed by carbonate facies towards the end of the Miocene (Al Khums and Sahabi formations). The sandstones of Arida Formation are important reservoirs in the Jālū Field (Barr and Weegar, 1972).

Figure 2 summarises the generalised time stratigraphy for the Upper Cretaceous–Tertiary succession with common terminology used for rock units of the Sirt Basin and Cyrenaica Platform (Al Jabal al Akhḑar Uplift).

PETROLEUM GEOCHEMISTRY

Source rock evaluation

The identification and characterization of source rocks are based on geochemical analyses performed in the Geological Laboratory of the Arabian Gulf Oil Company, Binghāzī on samples from seven deep wells drilled below 3048 m (10 000 ft). The analytical data include 240 total carbons (TCs), 186 total organic carbons (TOCs), and 240 Rock-Eval pyrolyses, whereas 29 vitrinite reflectance values are from eight wells and seven of these do not have TOC and Rock-Eval data. The present-day temperatures are from wireline-logging of 31 wells. The geochemical evaluation is helped by the authors' experience of the area and by the published and unpublished reports on Sirt Basin by Ghori (1986, 1991), Ghori and Sassi (1984), and Ghori and Mohammed (1996).

The TOC and Rock-Eval data is used to evaluate the hydrocarbon generating capacity of rocks while the present-day geothermal gradient, Rock-Eval parameter T_{max}, vitrinite reflectance, and geothermal history are used to evaluate the thermal maturity of rocks and timing of oil generation.

The rating of organic richness is based on samples containing below 1% TOC as poor to fair, 1 to 2% TOC as good, 2 to 4% TOC as very good and above 4% TOC as excellent. For Rock-Eval parameters the rating used (1) hydrocarbon generating potential – samples with potential yields (S_2) below 1 mg/g as poor to fair, 5 to 10 mg/g as good, 10 to 20 mg/g as very good and above 20 mg/g as excellent; (2) kerogen type – samples with hydrogen index values below 200 as predominantly gas generating, 200 to 350 as oil and gas generating, and above 350 as predominantly oil generating; (3) maturity–samples with T_{max} and production index values below 435°C and 0.1 as immature, 435°C to 470°C and 0.2 to 0.4 as oil-window mature, and above 470°C and 0.4 as gas-window mature.

The TOC and Rock-Eval data are plotted in Fig. 3 to illustrate the organic richness and generating potential of samples as a function of TOC versus parameter S_2 (Fig. 3a), kerogen type as a function of T_{max} versus hydrogen index (Fig. 3b), and kerogen maturity as a function of T_{max} versus production index (Fig. 3c). These plots indicate the presence of good to very good oil and gas source rocks that are within the oil-generative window; the plots also show that many samples either indicate oil shows or oil contamination from migrating oil or from drilling.

For individual wells, the TOC and Rock-Eval data

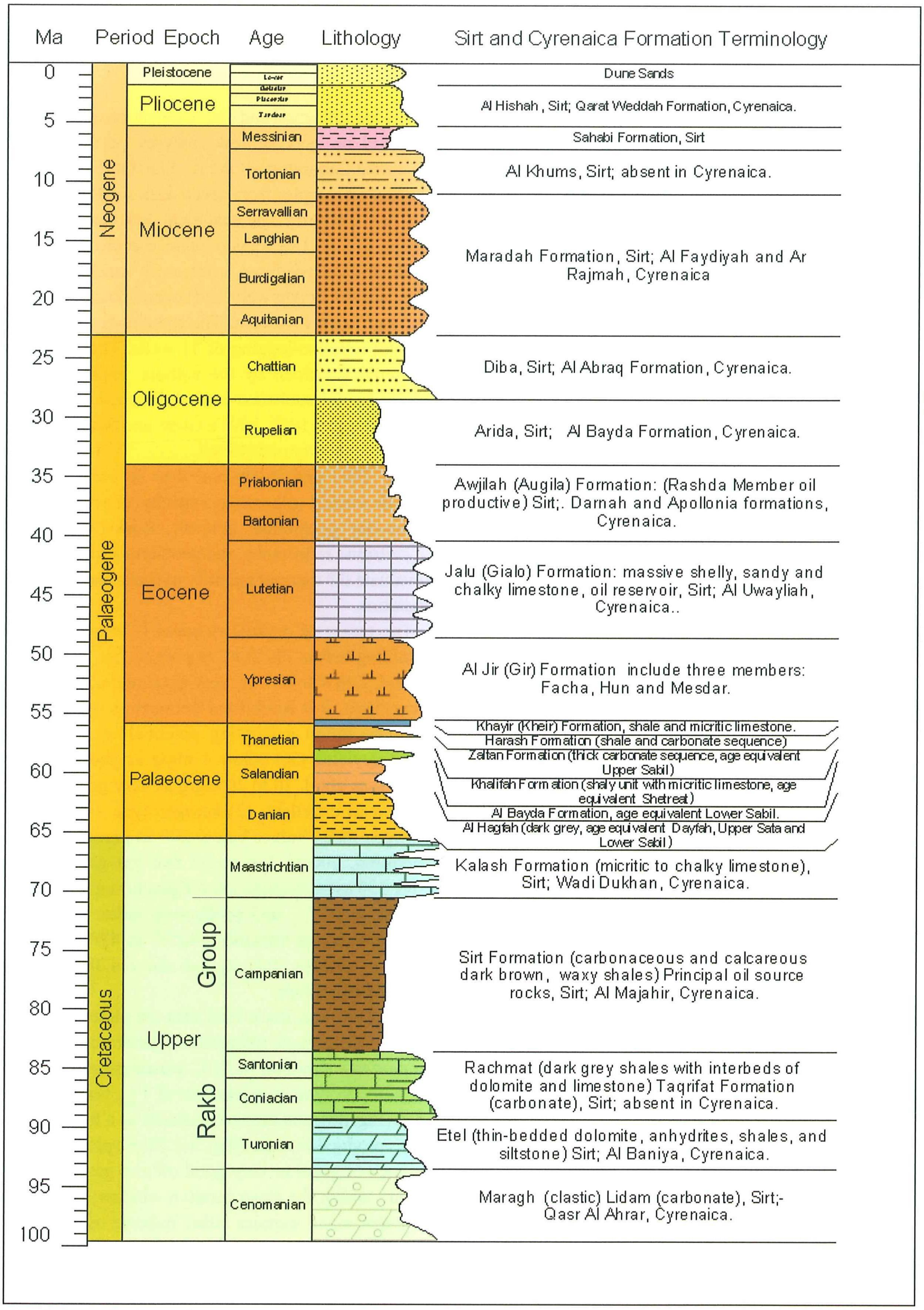

Fig. 2. Generalised Upper Cretaceous–Tertiary time-stratigraphy and common terminology used for rock units of the Sirt Basin and Cyrenaica (Al Jabal al Akhḑar Uplift) area.

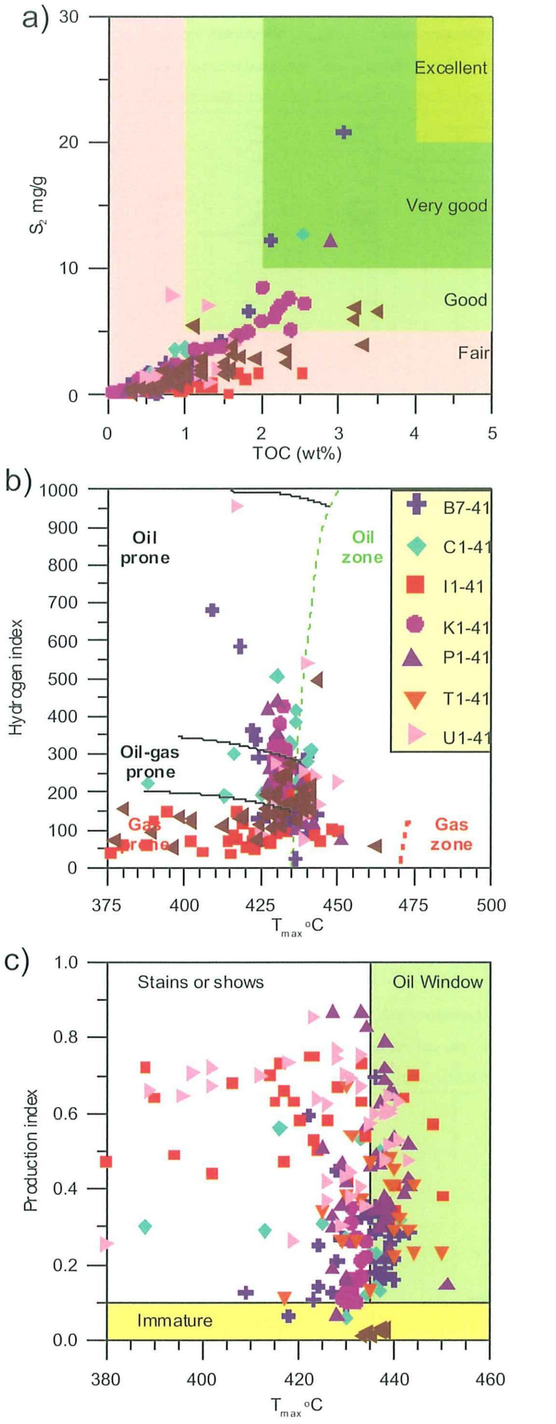

Fig. 3. TOC and Rock-Eval data plots: a) TOC versus S_2, indicating petroleum generating potential; b) T_{max} versus hydrogen index, indicating kerogen type; c) T_{max} versus production index, indicating maturity and samples with oil shows or stains.

are plotted in Fig. 4 to illustrate the organic richness, generating potential, kerogen type and thermal maturity of samples versus depth and rock units — B7-41 (Fig. 4a), C1-41 (Fig. 4b), I1-41 (Fig. 4c), K1-41 (Fig. 4d), P1-41 (Fig. 4e), T1-41 (Fig. 4f), and U1-41 (Fig. 4g).

The TOC and Rock-Eval data indicate that the shales within the Upper Cretaceous Sirt Formation are the most organic-rich and the best source rock of the area. The thickest and organically richest section is present in Ul-41 (Fig. 4g). In this well, the organic-rich shale section is over 488 m (1600 ft) thick between 4109–4602 m (13 480–15 100 ft), with average TOC of 2% ± l%. Within this section, the upper 244 m (800 ft) thick part is very rich with average TOC of 2.6% ± 0.8%. The second most organic-rich section is present in Kl-41 (Fig. 4e), where over 152 m (500 ft) thick section, from 388 m to a total depth of 3840 m (12 100 to 12 630 ft), with average TOC of 2.2% ± 0.2, which may extend below the total depth. The shale interval in Il-4l is approximately 213 m (700 ft) thick but it is mostly a gas generating type, where high-pressure gas is reported within the limestone section. The type of kerogen within the source rock samples is oil and gas-generating type II (Fig. 3b).

The TOC and Rock-Eval data also indicate thin organic-rich intervals within the Middle Eocene of the following wells: B7-4l (Fig. 4a), C1-41 (Fig. 4b), T1-41 (Fig. 4f), and U1-41 (Fig. 4g), but, except in the SW part, they are immature at these locations for forming source-rock.

PRESENT-DAY TEMPERATURE

Present-day subsurface temperatures are estimated from bottom hole temperatures (BHTs) recorded during wireline logging in 31 wells. Measured BHT is usually 10 to 15% lower than the actual formation temperature due to the short time interval between mud circulation and logging for the formation to attain thermal equilibrium and so require upward correction (Beck and Balling, 1988; Hermanrud *et al.*, 1990, 1991). In this study BHTs are corrected by using "Kehle's Correction Curve" developed by the GSNA (Geothermal Survey of North America, Kehle, 1971, 1972), which provides rough compensation for different times-since-circulation and is suitable for the type of temperature data available. The average geothermal gradient within the study area is 3.1°C/100 (1.7°F/100 ft. ± 0.3°F) using 26°C as surface temperature. The results of the present-day geothermal gradient are summarized in Table 1, and Fig. 5 shows the estimated subsurface temperatures recorded in the studied wells.

The gradient is computed by equation:

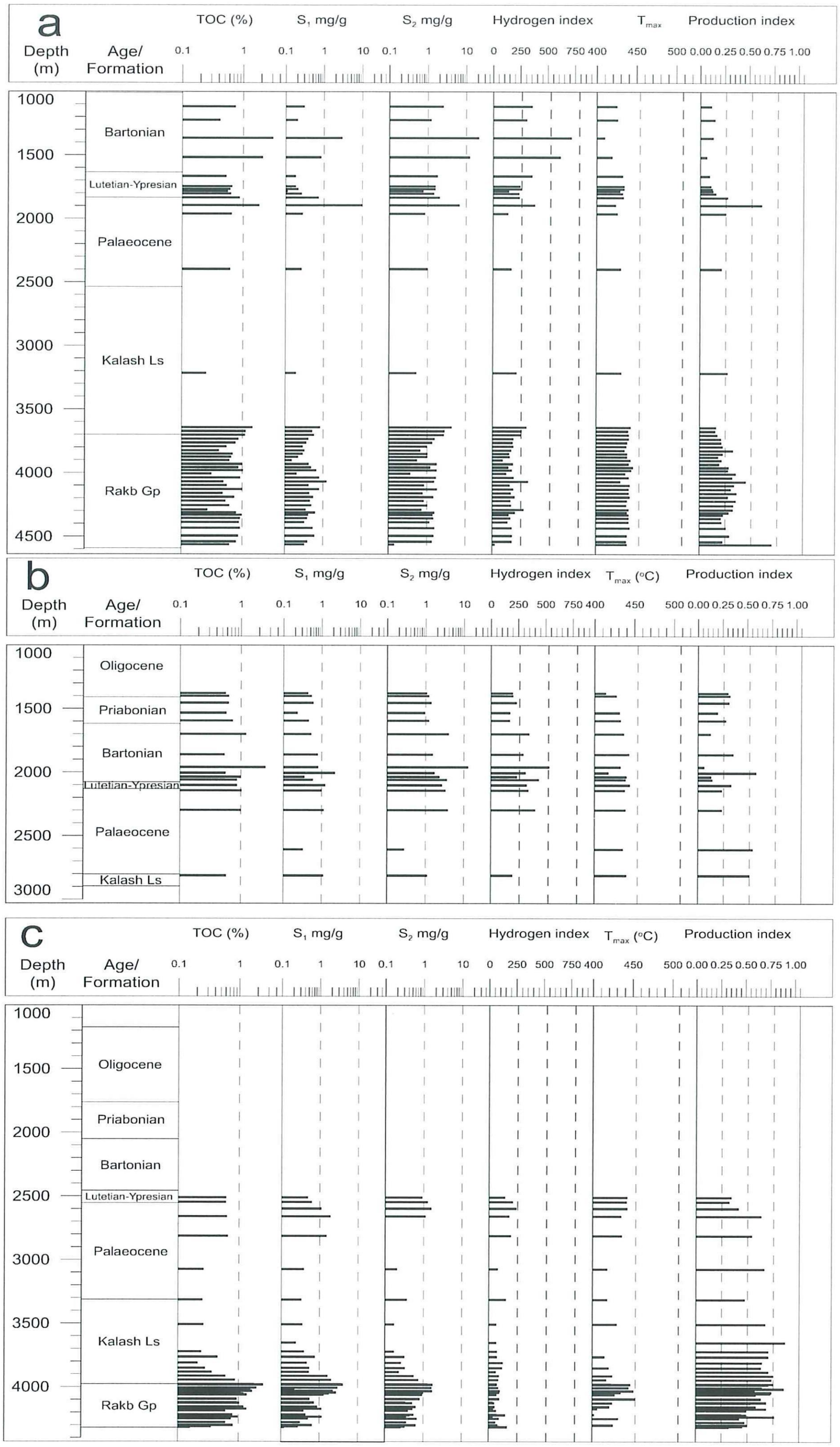

Fig. 4. Geochemical logs showing TOC and Rock-Eval data versus depth and rock units: a) B7-41; b) C1-41; c) I1-41.

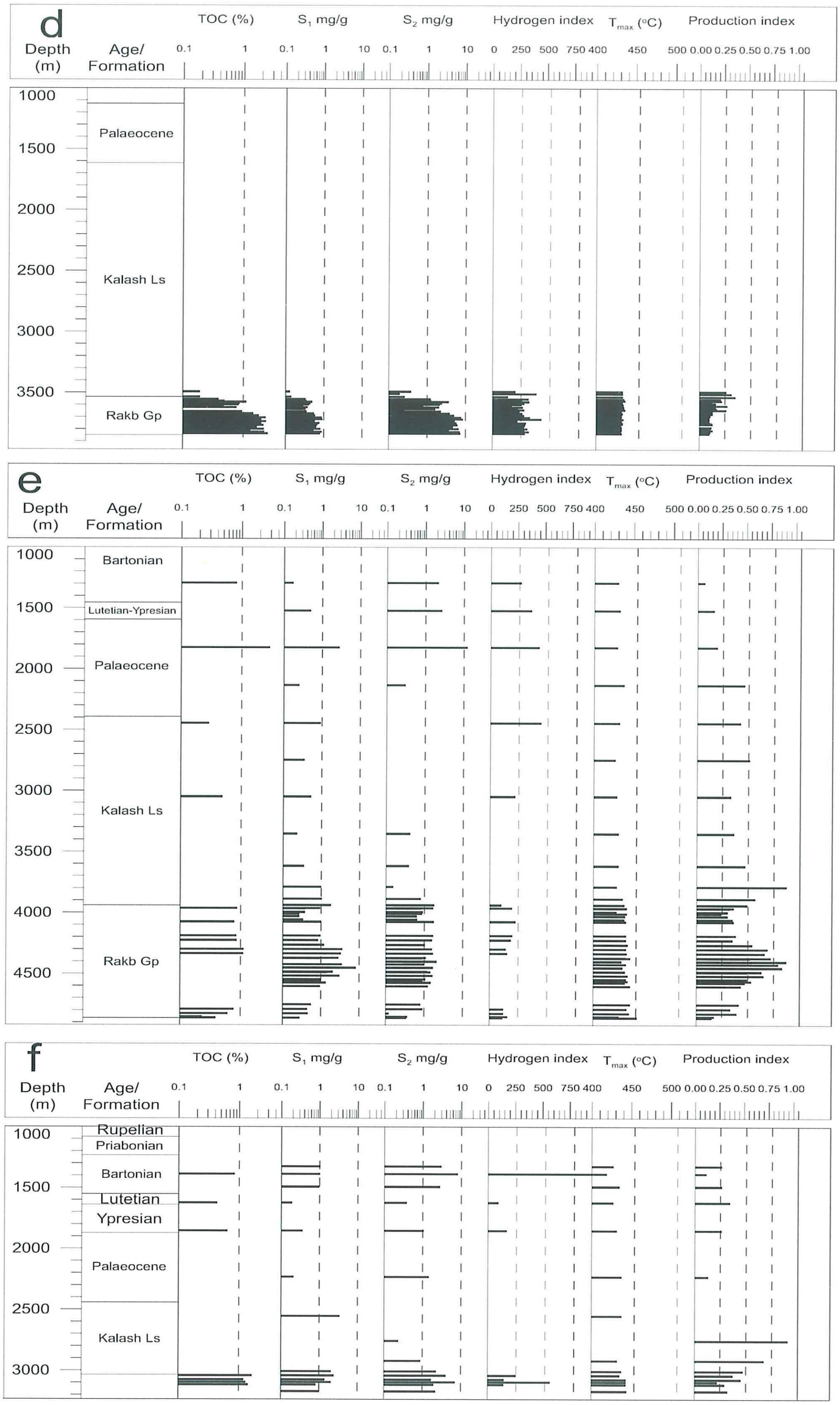

Fig. 4. Cont. Geochemical logs showing TOC and Rock-Eval data versus depth and rock units: d) K1-4; e) T1-41; f) P1-41.

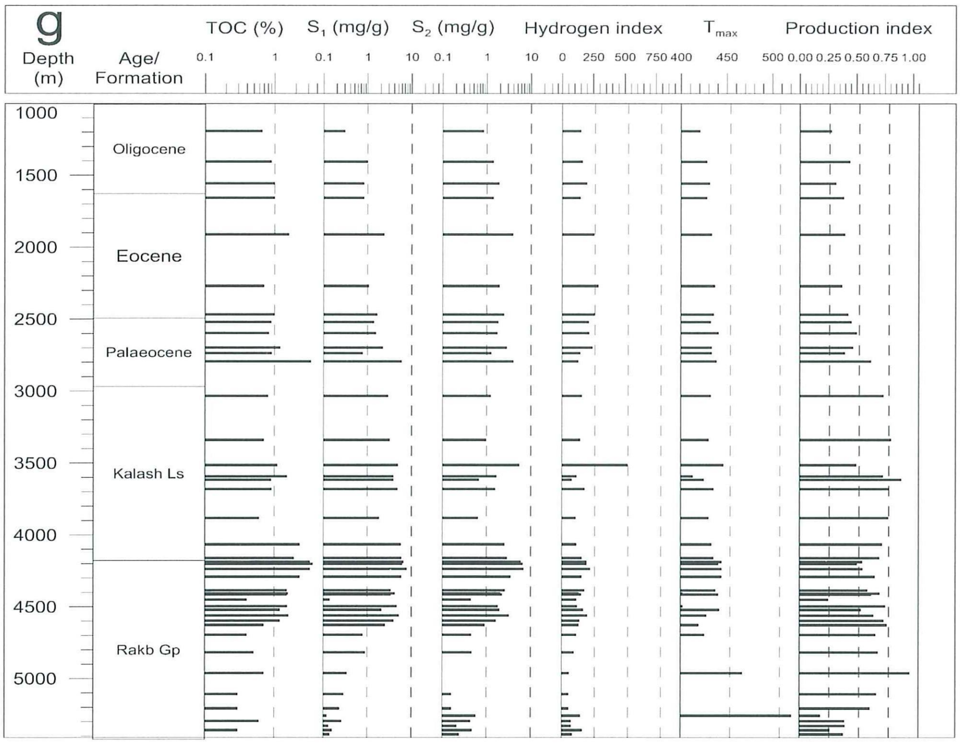

Fig. 4. Cont. Geochemical logs showing TOC and Rock-Eval data versus depth and rock units: g) U1-41.

$$\text{Gradient } ^\circ\text{C}/100\text{ m } (^\circ\text{F}/100\text{ ft}) = \frac{\text{BHT } ^\circ\text{C} - 26^\circ\text{C (Surface Temperature)} \times 100}{\text{Depth of BHT}}$$

The geothermal gradient of individual wells is computed by averaging the gradient found at different depths, and the gradient of the area is computed by averaging all the measurements made in 31 wells at different depths and lithologies.

PETROLEUM GENERATING MODELLING

The source-rock thermal maturation and hydrocarbon generation histories of 21 wells and a geological cross-section were simulated to calculate the timing of petroleum generation and migration in the study area, utilising the petroleum systems modelling software of Platte River Associates. The modelling was performed in three steps: (i) one-dimensional modelling of a single well location, utilising version 7.06 of BasinMod 1-D; (ii) one-dimensional modelling of multi-well locations, in version 7.06 of BasinView and (iii) two-dimensional modelling of a cross-section using version 4.17 of BasinMod 2-D.

In the first step, one-dimensional burial histories were

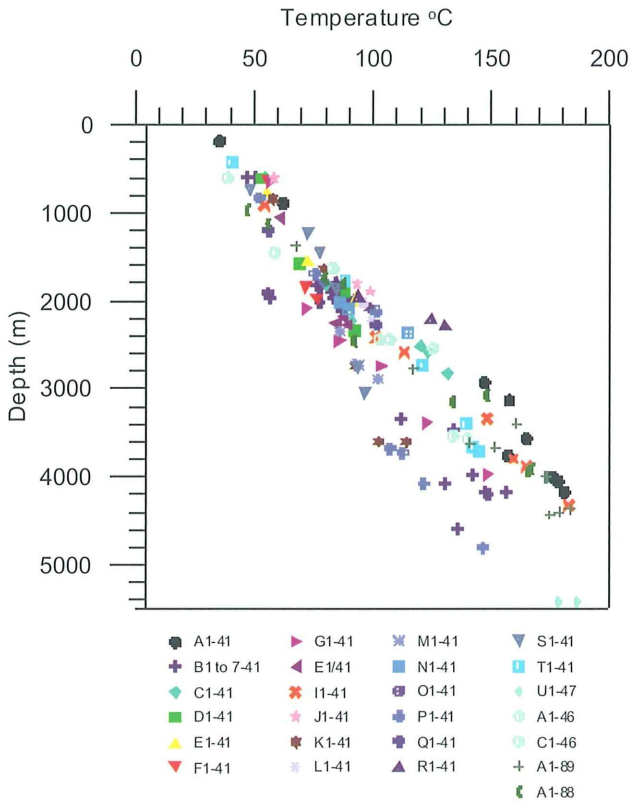

Fig. 5. Subsurface present-day temperatures from corrected BHT (°C) versus depth for 31 wells.

Table 1. Present-day subsurface temperature data for 31 wells within the study area.

Sample No.	*Well*	*TD (m)*	*TD (ft)*	*Estimated BHT °C*	*Estimated BHT °F*	*Estimated Gradient °C/100 m*	*Estimated Gradient °F/100 ft*
1	A1-41	4179.7	13713	186.7	368	3.8	2.10
2	B1-41	1989.7	6528	92.2	198	3.2	1.80
3	B2-41	2118.1	6949	86.7	188	2.0	1.55
4	B3-41	2078.7	6820	91.1	196	3.1	1.70
5	B4-41	2089.1	6854	89.4	193	3.0	1.65
6	B6-41	2083.6	6836	91.1	196	3.1	1.70
7	B6-41	4234.9	13894	153.9	309	3.0	1.65
8	B7-41	4593.3	15070	143.9	291	2.5	1.40
9	C1-41	2895.6	9500	21.1	70	3.6	2.00
10	D1-41	2363.4	7754	95.6	204	2.9	1.60
11	E1-41	2021.7	6633	95.0	203	3.3	1.85
12	F1-41	1983.9	6509	77.2	171	2.5	1.40
13	G1 -41	4007.5	13148	143.3	290	2.9	1.60
14	Hl-41	2281.7	7486	88.9	192	2.7	1.50
15	I1-41	4320.8	14176	176.1	349	3.4	1.90
16	J1-41	2098.5	6885	101.1	214	3.5	1.95
17	K-4.1	3849.6	12630	125.0	257	2.5	1.40
18	L1 -41	2237.2	7340	102.2	216	3.3	1.85
19	Ml -41	2888.0	9475	100.6	213	2.5	1.40
20	N1-41	2376.8	7798	104.4	220	3.2	1.80
21	O1-41	1990.3	6530	81.1	178	2.7	1.50
22	P1-41	4864.6	15960	155.0	311	2.6	1.45
23	Q1-41	2276.9	7470	101.1	214	3.2	1.80
24	R1-41	2279.9	7480	116.1	241	3.9	2.15
25	S1-41	3054.1	10020	118.3	245	3.0	1.65
26	T1-41	3710.6	12174	148.3	299	3.2	1.80
27	U1-41	5421.8	17788	185.0	365	2.9	1.60
28	A1-46	3575.6	11731	140.6	285	3.2	1.75
29	C1 -46	2654.5	8709	121.1	250	3.5	1.95
30	Al -39	4441.5	14572	176.7	350	3.3	1.85
31	Al-88	3939.2	12924	159.4	319	3.3	1.85
	Average based on 150 temperature recordings in 31 wells					3.1	1.70

reconstructed from the stratigraphic sections and their lithologies encountered in wells. The thermal histories were reconstructed using estimated erosional histories and adjusting thermal conductivities and transient heat flow to constrain maturity models versus measured data. Corrected BHTs, T_{max} and vitrinite reflectance values were used to constrain present-day and palaeotemperatures. The depth of the oil window is used as an equivalent for the burial depths required for the conversion of 10% to 90% of the available kerogen to petroleum. On the basis of the geochemical data, source rocks are assumed to be initially type II kerogen. The following vitrinite reflectance values are adopted to define maturation stages: immature zone, less than 0.5% Ro; early mature, 0.5% to 0.7% Ro; mid-mature, 0.7% to 1.0% Ro; late mature, 1.0% to 1.3% Ro; and mainly gas generation, over 1.3% Ro. The following options of Platte River BasinMod were used in modelling: Bmod 2-D fluid flow compaction, power function for permeability calculation, and transient heatflow with 26°C and 20°C present-day sediment surface temperatures for onshore and offshore wells, respectively. The calculated maturities, and timing of petroleum generation, are based on Lawrence Livermore National Laboratory (LLNL) vitrinite and kerogen kinetics, respectively.

The one-dimensional geothermal history of seven wells with TOC and Rock-Eval data were undertaken to reconstruct depth interval and timing of petroleum generation for the Upper Cretaceous source rocks. The top and bottom depth of the oil-generative window varies between 2000–2500 m and 3500–4500 m, with the peak oil-generative zone below 3000 m. The generation histories of two representative wells (B7-41 and U1-41) are shown in Fig. 6.

In the second step, the regional maturity trends at stratigraphic levels of the Upper Cretaceous, Palaeocene and Eocene were calculated from one-dimensional modelling of 21 wells (Fig. 7). The burial histories of these wells were reconstructed from preserved major stratigraphic units and their lithologies. In the third and final step, the maturity across the basin was calculated by two-dimensional modelling of a geological cross-section, constructed from the wells used in the one-dimensional modelling to evaluate the petroleum systems (Fig. 8).

Figure 6 shows optimisation of models against measured versus calculated present-day and palaeotemperatures and maturity (Fig. 6i), burial histories (Fig. 6ii), and the modelled transformation ratio and generation rate versus time as a function of burial history (Fig. 6iii) for U1-41 (Fig. 6a) and B7-41 (Fig. 6b) because these wells have maximum data to characterize source rocks and model maturity for the Upper Cretaceous source rocks. In U1-41, the Rakb Group source beds within the Sirt Formation are at the late mature stages of oil generation and their generation rate peaked during the Oligocene–Miocene (Fig. 6a–iii). By comparison, these Upper Cretaceous source beds are within the oil-generative window and their generation rate peaked during the Pliocene (Fig. 6b–iii).

Figure 7 shows the regional maturity at the top of the Upper Cretaceous Rakb Group (Fig. 7a), Palaeocene (Fig. 7b), and Eocene (Fig. 7c). The maturity increases towards the west and southwest within Ajdābiyā Trough, probably due to increasingly deeper burial – the Upper Cretaceous was intersected at 1615 m in K1-41 in the northeast, and at 3719 m in A1-89 in the southwest, the Palaeocene at 1128 m in K1-41 and at 3618 m in A1-89, and the Eocene is very shallow in K1-41 and at 3121 m in A1-89.

PETROLEUM SYSTEMS

For this study, the available geochemical data are insufficient to differentiate the numerous petroleum shows within the study area of the Ajdābiyā Trough into discrete families or to correlate them with recognized source rocks of the study area to define possible petroleum systems *sensu* Magoon and Dow (1994). However, the regional stratigraphic distribution of likely source, reservoir and seal rocks limits the number of possible petroleum systems to those that may be charged by the source rocks of Sirt Formation (Rakb Group), Palaeocene, and Eocene.

The Ajdābiyā Trough is the most important source rock pod for several active petroleum systems of Sirt Basin. The oil is trapped within the trough as well as having migrated westward onto the Zalṭan Platform and eastwards towards the Cyrenaica Platform and eastern Sirt embayment. Oil is also discovered at Antlat, A1-NC 129, B1-NC 129 and C1-NC 129 (Hallett, 2002).

Two-dimensional modelling of a geological section was undertaken to evaluate the likelihood of active petroleum systems within the study area of the Ajdābiyā Trough; the model was constrained by data from six wells (Figs 8a, b) that indicates the possibility of petroleum charge from the Upper Cretaceous source rocks within the study area of Ajdābiyā Trough. The charge possibilities from the Palaeocene and Eocene source rocks increase towards the deeper SW parts of Ajdābiyā Trough.

Figure 9 summarises timing of maturation and peak oil generation for the Upper Cretaceous source rocks in U1-41 and B7-41. Within the deeper parts of the basin the timing of peak oil generation was Palaeocene–Miocene as indicated by U1-41, whereas within the shallower parts it was Eocene-Recent as indicated by B7-41 (Fig. 9).

The Upper Cretaceous in most parts, and the Palaeocene and Eocene towards the SW part of the study area show good petroleum source rock possibilities. The shale percentage within the Upper Cretaceous sequence increases from about 5 to 40 percent from the E and NE to the W and SW parts of the area, thus indicating source rock possibilities.

The TOC and Rock-Eval data for the Rakb Group indicate that the Etel Formation equivalent unit in the study area is represented by comparatively thin, dark coloured shales interbedded with limestone, which is penetrated in Pl-41 (Fig. 4e), T1-41 (Fig. 4f) and U1-41 (Fig. 4g), and is shown in the figures as undifferentiated Rakb Group. The TOC and Rock-Eval data suggest it is a non-source unit. The Taqrifat Formation equivalent is mainly represented by dark grey limestone with dark shale intervals, over 762 m (2500 ft) thick in Ul-41, and over 610 m (2000 ft) in B7 and Pl-41, which is also a non-source unit; high-pressure gas in Il-41 and oil shows in Pl-4l are present in this unit. The Sirt Formation equivalent however is mainly represented by calcareous to very

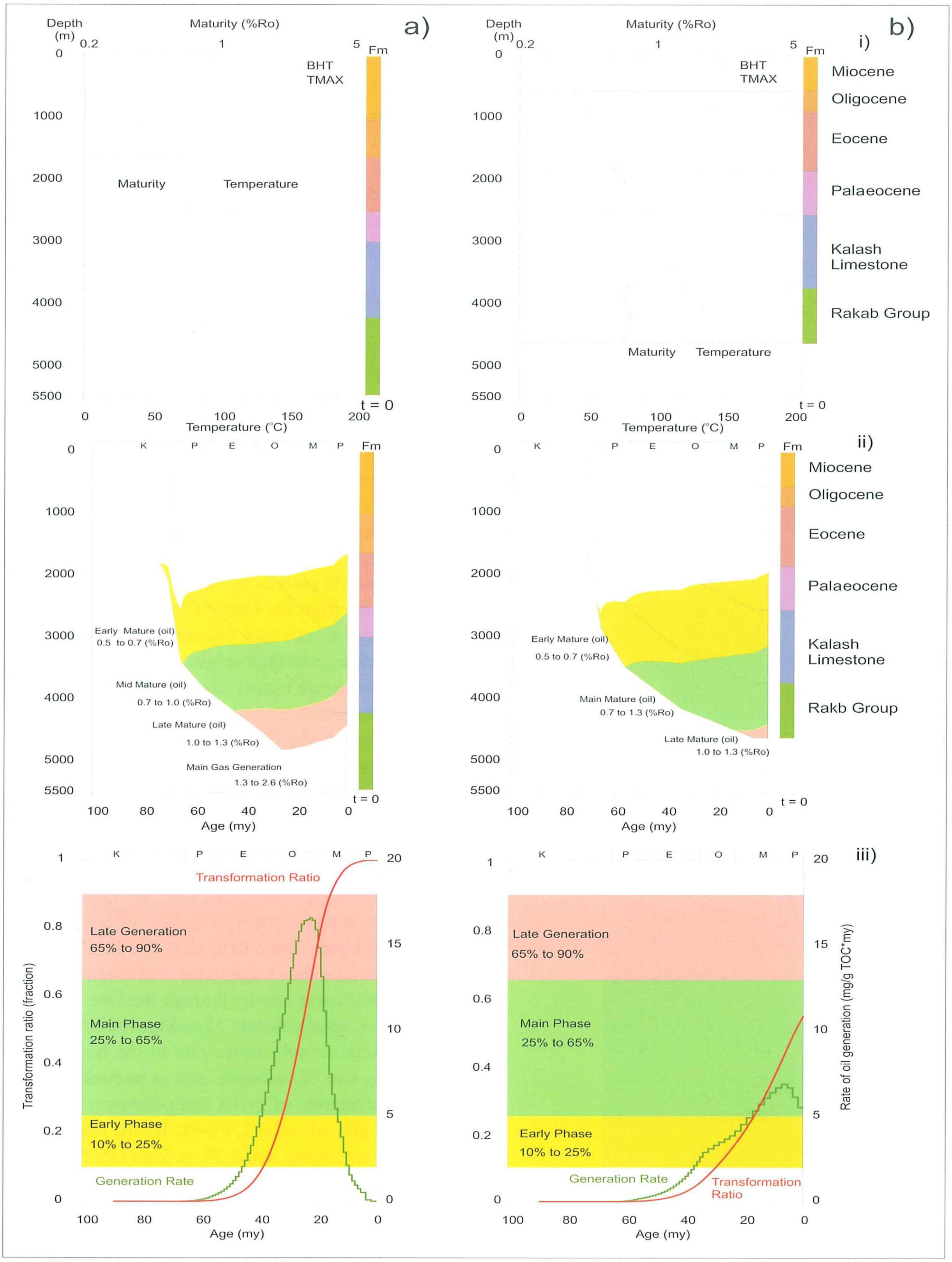

Fig. 6. Petroleum generation modelling (a) U1-41 and (b) B7-41: i) calculated versus measured temperature and maturity; ii) burial history; iii) transformation ratio and rate of oil generation.

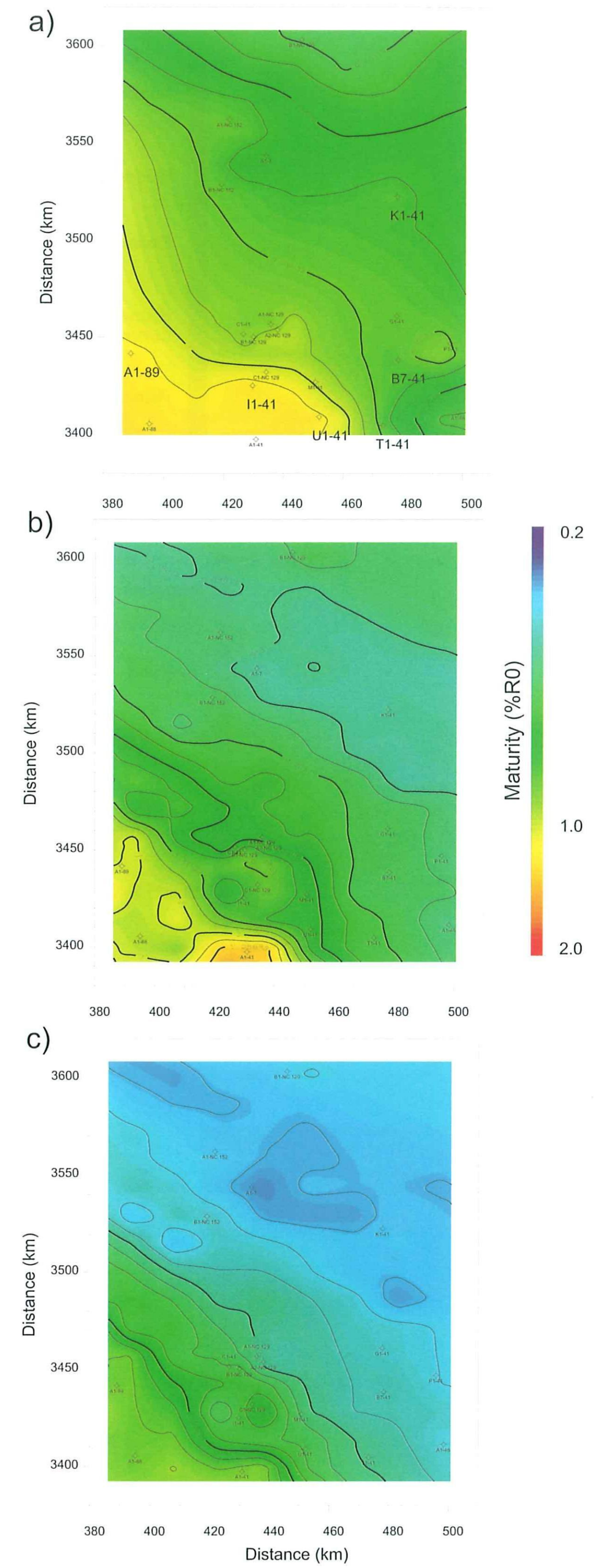

Fig.7. Present-day vitrinite reflectance maturity at the top of: a) Upper Cretaceous Rakb Group; b) Palaeocene; c) Eocene.

calcareous shales and marls dark brown, dark grey, and black in colour. Its thickest development is in the Ul-41 area, approximately 457 m (1500 ft) thick, although it is generally 213 to 152 m (700 to 500 ft) thick. Its thickness reduces, and its depth increases in the SW part (Al-89) 70 m (230') and Al-41, 110+ m (360'+). The TOC and Rock-Eval data indicate it to be the best source rock in the area, with good to rich oil and gas generating capacity which might have generated good commercial quantities of hydrocarbons in the area, especially around Ul-4l and Kl-41.

The Palaeocene and Eocene sequences are mature only in the SW corner of the study area. They are represented by a very thick development of predominantly carbonate facies, 457 m to 1219 m (1500' to 4000') thick. Their shale percentage increases and their thickness decreases towards the SW parts where they become mature and the source possibilities increase. The geochemical data indicate thin intervals with high TOC and Rock-Eval parameters and S_1 and S_2 values within the Palaeocene and Middle Eocene, indicating either migrated hydrocarbons from the deeply buried mature source rocks of the Eocene or Palaeocene in the west and SW parts of the basin, or vertically migrated hydrocarbons from the Upper Cretaceous source rocks. Detailed source rock and oil-source correlation studies are required to prove their origin.

The geothermal history also reflects the tectonics of the area; the basin is shallow in the NE and gradually deepens towards the SW. In the NE (B7-41, P1-41, Gl-41), basin subsidence was comparatively faster during the Late Cretaceous to Middle Eocene, approximately 81 m/Ma (265 ft/Ma). After the Middle Eocene it slowed to approximately 23 m/Ma (75 ft/Ma) until uplifting of the basin. In the SW however , the subsidence rate was the reverse, being slow during the Late Cretaceous and Palaeocene, approximately 15 m/Ma (50 ft/Ma) and fast after the Palaeocene, approximately 73 m/Ma (240 ft/Ma; Al-89). The subsidence rate in the area around the U1-41 and Il-4l wells was similar through the Late Cretaceous and Tertiary, approximately 55 m/Ma (180 ft/Ma).

The burial or subsidence rate of the basin controls the heating rate of sediments and is responsible for the thermal maturation of rocks and petroleum generation. In the NE (K1-41, G1-41, P1-41, B7-4l) the burial rate was slow, averaging about 38 m/Ma (125 ft/Ma), thus only the Upper Cretaceous source rocks are mature for oil generation. In the SW however (Al-41, Il-4l, Al-89) the burial rate was fast, averaging about 61 m/Ma (200 ft/Ma), where source rocks within the Eocene and Palaeocene approach oil-generative maturity, and the

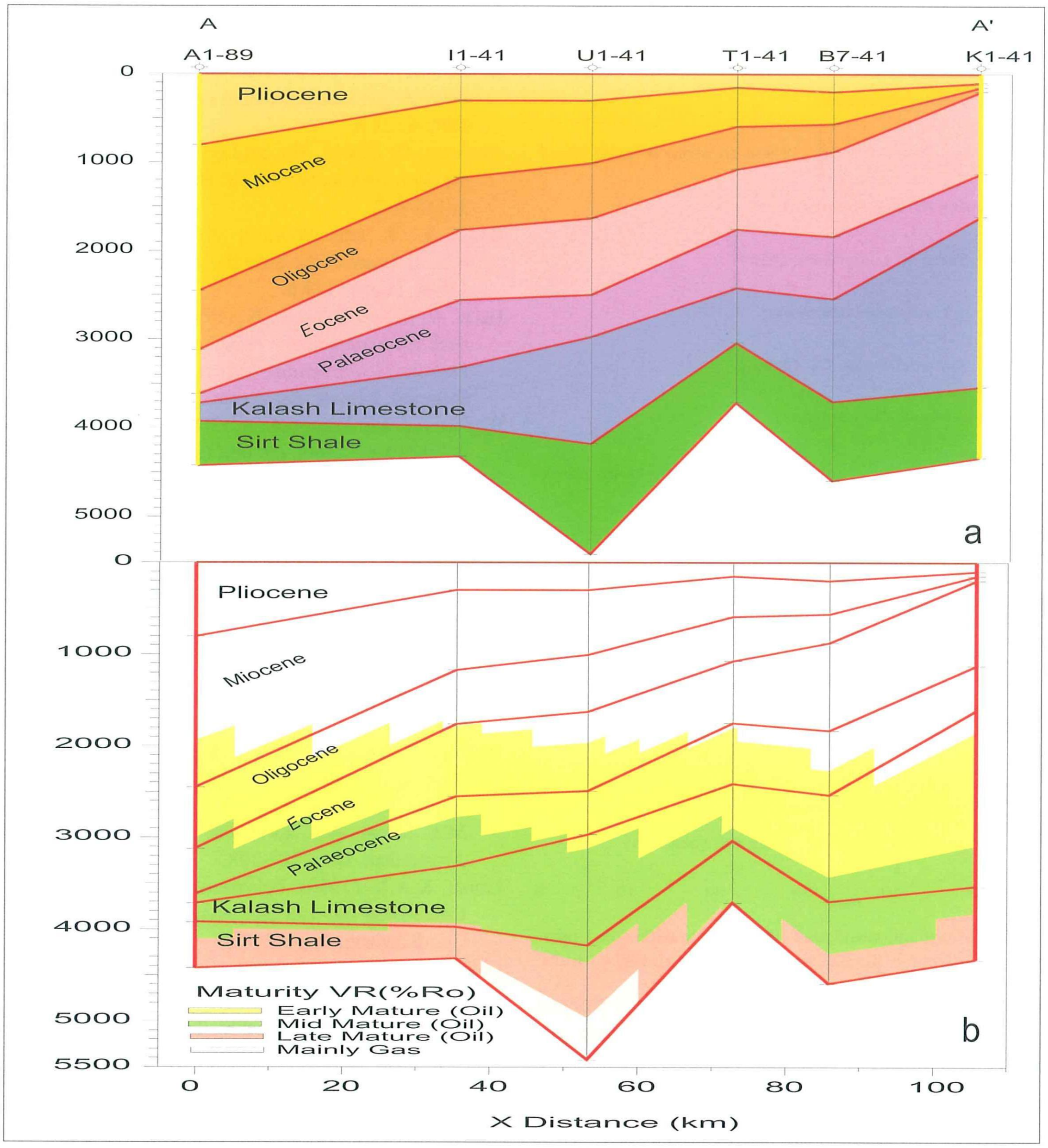

Fig. 8. Present-day maturity of geological cross-section: a) section modelled from A1-89 in the SW to K1-41 in the NE; b) maturity of section from A1-89 to K1-41, based on two-dimensional modelling. Well locations are shown in Fig. 7.

Upper Cretaceous source rocks approach over maturation for oil generation (Fig. 7).

CONCLUSIONS

The total organic carbon content, Rock-Eval pyrolysis, present-day temperatures, and petroleum system modelling indicate one effective and two potential petroleum systems that may be charged by source rocks within the Upper Cretaceous Sirt Formation (Rakb Group), the Palaeocene and Eocene, respectively.

The study area of the Ajdābiyā Trough is shallow in the E and NE, with an average subsidence rate of 38 m/Ma (125 ft/Ma), whereas in the W and SW it is deep with an average subsidence rate of 61 m/Ma (200 ft/Ma).

The best source rocks in the area are within the Upper Cretaceous Sirt Formation (Rakb Group), with good to very good oil and gas generating capacity. They are thermally mature in most of the area, approaching

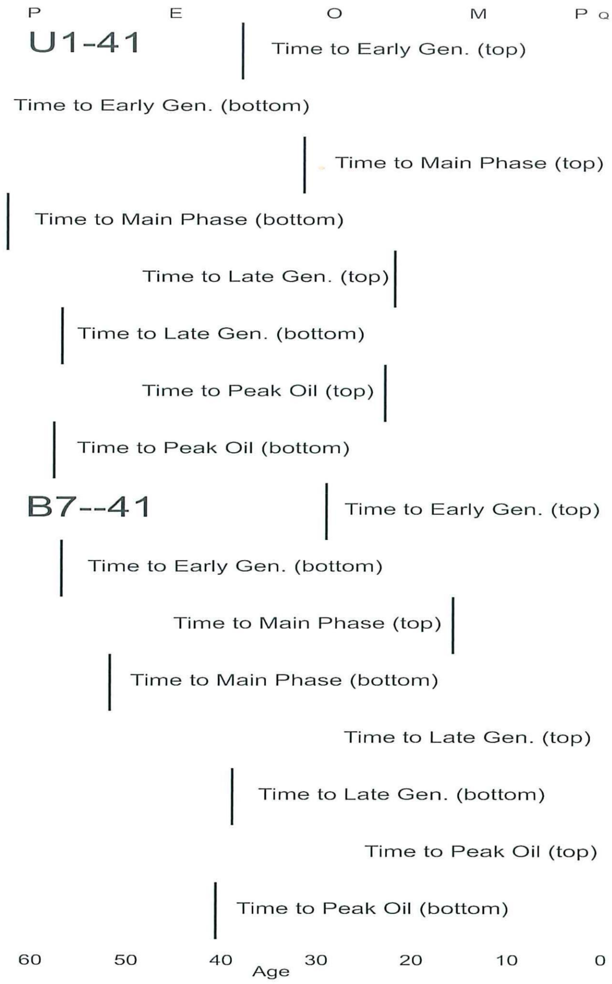

Fig. 9. Timing of maturation and peak oil generation within the Upper-Cretaceous Rakb Group in the area around the U1-41 and B7-41 wells.

over maturation for oil generation towards the deeper SW part. The best oil and gas generating areas are around U1 and Kl-41. These source beds could have generated significant quantities of oil and gas since the Eocene.

The second-best source rocks of the area are the comparatively thin shaly intervals within the Palaeocene and Eocene sequences, but they are thermally mature only in the W and SW of the basin.

The average present-day geothermal gradient is 3.1°C/100 m (1.7°F/100 ft) and the oil-generative window lies between 2500 and 4000 m with the peak oil-generative zone below 3000 m.

The origin of the small oil accumulation in Bl-4l and several oil shows encountered in different wells within the Palaeocene and Eocene is uncertain and requires detailed oil-source correlation studies to evaluate the Palaeocene and Eocene petroleum systems.

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