

## Research paper

## Source rocks and related petroleum systems of the Chelif Basin, (western Tellian domain, north Algeria)



Mohamed Arab<sup>a, b</sup>, Rabah Bracène<sup>a</sup>, François Roure<sup>c, d</sup>, Réda Samy Zazoun<sup>e, \*</sup>, Yamina Mahdjoub<sup>b</sup>, Rabie Badji<sup>a</sup>

<sup>a</sup> Sonatrach-Division Exploration, Avenue du 1<sup>er</sup> Novembre Bat 'C' BP 68M, Boumerdès, Algeria

<sup>b</sup> Faculté des Sciences de la Terre, de la Géographie et de l'Aménagement du Territoire, USTHB, BP 32, Bab Ez Zouar, Algiers 16111, Algeria

<sup>c</sup> Geosciences Department, IFP Energies nouvelles, Rueil-Malmaison, France

<sup>d</sup> Tectonic Group, Utrecht University, The Netherlands

<sup>e</sup> Sonatrach-Division Technologies et Développement, Avenue du 1<sup>er</sup> Novembre, Boumerdès, Algeria

## ARTICLE INFO

## Article history:

Received 25 June 2014

Received in revised form

9 March 2015

Accepted 23 March 2015

Available online 31 March 2015

## Keywords:

Tellian nappes

Pull-apart basin

Tliouanet field

Algeria

Oil expulsion

Petroleum systems

## ABSTRACT

In the Chelif basin, the geochemical characterization reveals that the Upper Cretaceous and Messinian shales have a high generation potential. The former exhibits fair to good TOC values ranging from 0.5 to 1.2% with a max. of 7%. The Messinian series show TOC values comprised between 0.5 and 2.3% and a high hydrogen index (HI) with values up to 566 mg HC/g TOC. Based on petroleum geochemistry (CPLC and CPGC) technics, the oil-to source correlation shows that the oil of the Tliouanet field display the same signature as extracts from the Upper Cretaceous source rocks (Cenomanian to Campanian). In contrast, oil from the Ain Zeft field contains oleanane, and could thus have been sourced by the Messinian black shale or older Cenozoic series. Two petroleum systems are distinguished: Cretaceous (source rock) – middle to upper Miocene (reservoirs) and Messinian (source rock)/Messinian (reservoirs). Overall, the distribution of Cretaceous-sourced oil in the south, directly connected with the surface trace of the main border fault of the Neogene pull-apart basin, rather suggests a dismigration from deeper reservoirs located in the parautochthonous subthrust units or in the underthrust foreland, rather than from the Tellian allochthon itself (the latter being mainly made up of tectonic mélange at the base, reworking blocks and slivers of Upper Cretaceous black shale and Lower Miocene clastics). Conversely, the occurrence of Cenozoic-sourced oils in the north suggests that the Neogene depocenters of the Chelif thrust-top pull-apart basin reached locally the oil window, and therefore account for a local oil kitchen zone. In spite of their limited extension, allochthonous Upper cretaceous Tellian formations still conceal potential source rock layers, particularly around the Dahra Mountains and the Tliouanet field. Additionally they are also recognized by the W11 well in the western part of the basin (Tahamda). The results of the thermal modelling of the same well shows that there is generation and migration of oil from this source rock level even at recent times (since 8 Ma), coevally with the Plio-Quaternary traps formation. Therefore, there is a possibility of an in-situ oil migration and accumulation, even from Tellian Cretaceous units, to the recent structures, like in the Sedra structure. However, the oil remigration from deep early accumulations into the Miocene reservoirs is the most favourable case in terms of hydrocarbon potential of the Chelif basin.

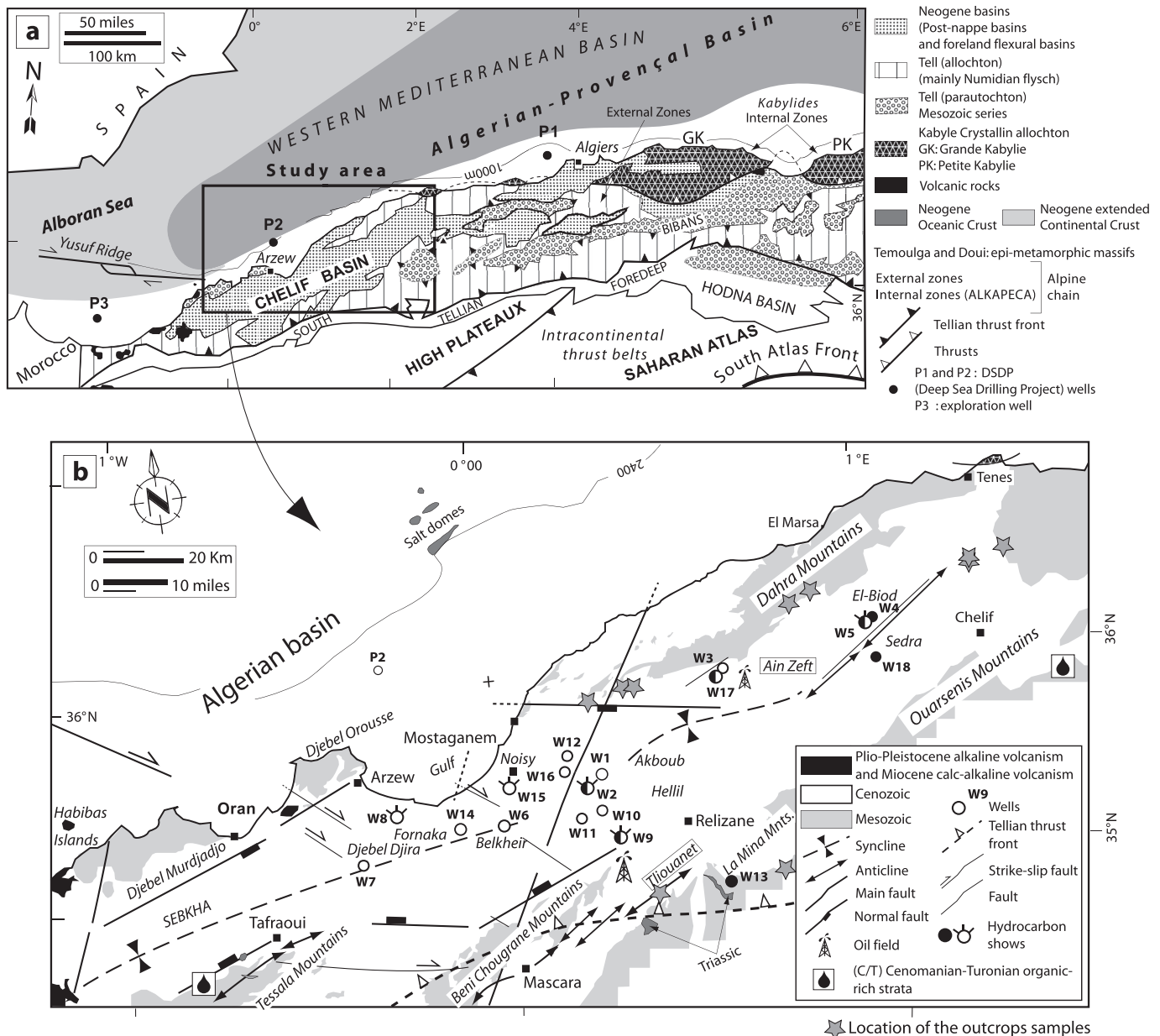
© 2015 Elsevier Ltd. All rights reserved.

## 1. Introduction

The study area is located in the external zone of the Rif-Tell or Maghrebides fold-and-thrust belt which is part of the southernmost segment of the Alpine orogen (Durand-Delga et al., 1980; Bracène and Frizon de Lamotte, 2002; Roure et al., 2012) and trends roughly east-west in northern Algeria (Fig. 1a–b). The Chelif Basin is a predominantly Neogene transtensional basin located

\* Corresponding author.

E-mail addresses: [Mohamed.arab@ep.sonatrach.dz](mailto:Mohamed.arab@ep.sonatrach.dz) (M. Arab), [redasamy.zazoun@ep.sonatrach.dz](mailto:redasamy.zazoun@ep.sonatrach.dz) (R.S. Zazoun).



**Figure 1.** (a) Geological setting of the Chelif Basin and wells location map and petroleum results (b).

within the Northern Algerian foothills. It is part of the African margin and located southwest of the “Dorsale calcaire” which constitutes the surface expression of the paleo-suture between (1) exotic terranes of European affinities (Kabylides Crystalline Massifs and associated Mesozoic to Eocene sedimentary cover) and (2) the Tellian allochthon. The Chelif basin consists of Mesozoic basinal units derived from the former passive margin of North Africa (Benaouali-Mebarek et al., 2006, and references therein). The Neogene sedimentary infill of the Chelif Basin rests on top of allochthonous basinal Mesozoic to Paleogene shales, carbonates and sandstone units of the southern Tellian allochthon.

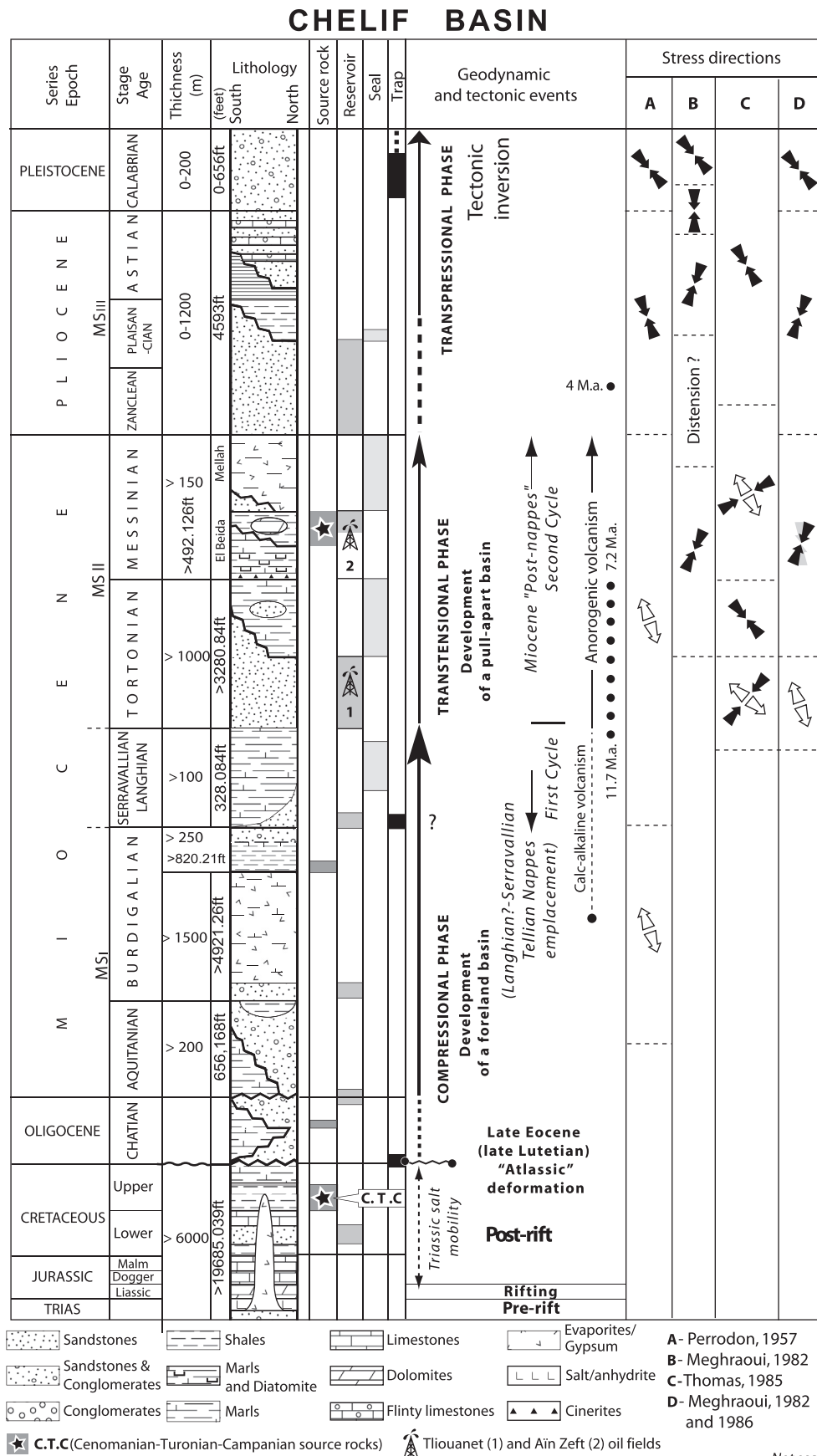
Since the discovery of the oil fields of Ain zeft and Tliouanet in the Chelif Basin in 1872 followed by the discovery of oil at Oued Gueterini in 1948 in the Hodna area (Kheidri et al., 2007), Northern Algeria constitutes an interesting zone for hydrocarbon (HC) exploration. However, the origin of the discovered oil is still under debate.

The aim of this paper is to (1) identify potential source rocks in the Chelif Neogene Basin and in its allochthonous Tellian substratum, as well as in the underlying foreland, (2) establish oil to source rock correlations in order to trace the origin of the oils in the producing fields, (3) assess the timing of HC migration and trapping, and (4) define the main petroleum systems.

## 2. Geological framework

### 2.1. Neogene sedimentary infill of the Chelif Basin

The Chelif Basin is located in the western part of the Tellian Atlas. It is an elongated basin spanning 350 km in ENE-WSW direction (Fig. 1a) filled by Miocene to Pliocene series on Mesozoic and Paleogene substratum (Figs. 2 and 3). The Jurassic sediments are characterized by calcareous deposits while the Cretaceous sediments are mainly composed of sandstones at its base that are



**Figure 2.** Typical Neogene litho-stratigraphic section and petroleum systems chart of the Chelif Neogene Basin and its substratum.

grading upward into an assemblage of limestones, shales and marls. The thickness of both formations varies from hundreds to thousands of metres (max. 6000 m). The Oligocene facies consists of sandstone deposits changing laterally to dark grey shale (Fig. 2) whose thickness reaches 500 m in the deep basin. The Neogene sedimentary infill can be subdivided into 3 distinct megasequences MSI, MSII and MSIII (Neurdin-Trescartes, 1992, 1995; Fig. 2):

At the base, the marine Lower Miocene megasequence (MSI) was deposited during a compressional episode in a piggyback position on top of the still moving Tellian allochthon. During the Middle Miocene, the sedimentary deposits preserved on top of the Tellian units and especially in the western sub-basin of the Chelif record the influence of arc-related alkaline and calc-alkaline volcanism. The Aquitanian is represented by conglomerates and sandstones. These change laterally into grey marls containing traces of gypsum. At the northern border, the Burdigalian is composed of conglomerates and continental red sandstones. The Langhian contains sandstones and conglomerates at its basal part, with a lateral facies change to sandstones intercalated with blue marls (Fig. 2).

The thicker Tortonian–Messinian megasequence (MSII) was deposited during the formation of the thrust-top pull-apart basin during an episode of transtension. It comprises dominantly marine siliciclastic deposits at the base, grading into marl, siliciclastics and volcanic debris such as cinerites that are considered as a chronologic marker at the base of the Messinian deposits (Kieken, 1974). At the base of this series, there is a development of sandstone bodies. The Messinian Tripoli formation consists of an alternation of dark grey marls and thin diatomite layers, it is grading upward into an alternation of gypsiferous dark-grey marls and microcrystalline anhydrite. Laterally, the Tripoli formation changes to grey marls and to the lithotamnium limestone (Anderson, 1936; Perrodin, 1957; Rouchy, 1982). The sedimentary cycle began with a transgression at Early Tortonian that is marked by the presence of glauconite and deposition of sandstones. The high concentration of planktonic neritic-oceanic diatomite at Early Messinian (Mansour et al., 2008) indicates a deep environment. Finally, the gypsiferous marls are deposited during the Messinian salinity crisis (Hsü,

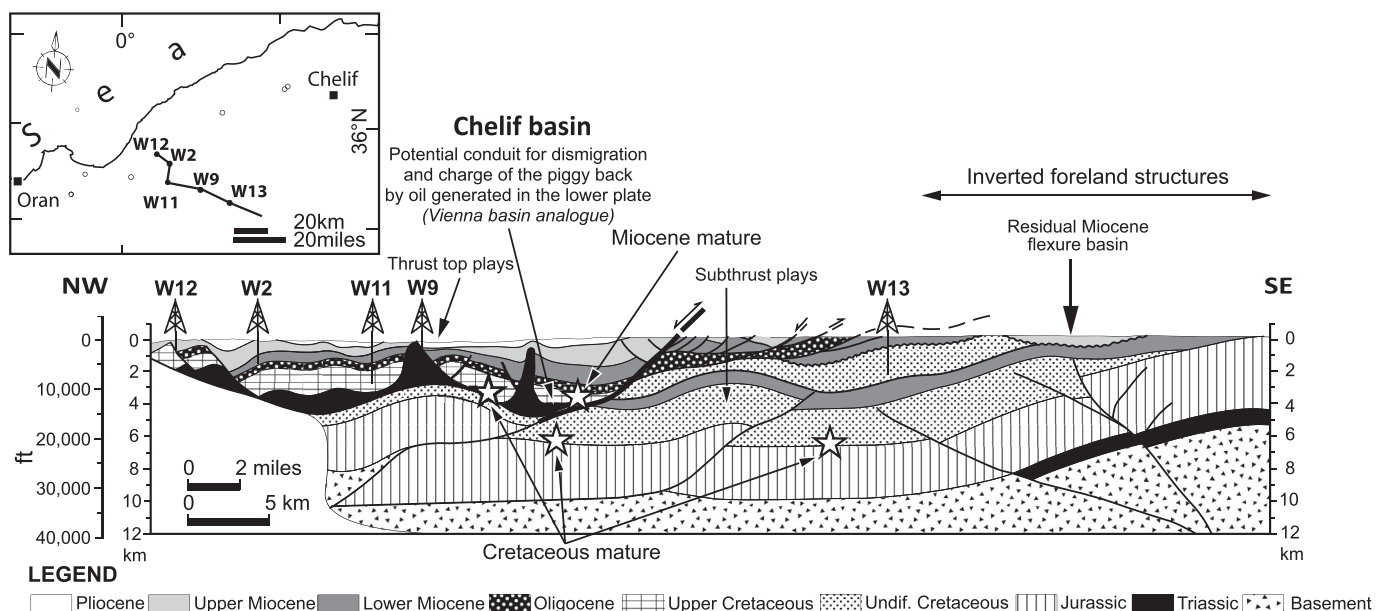
1971; Ryan, 2011) which occurred throughout the Mediterranean Sea.

The Plio-Pleistocene sequence (MSIII) was deposited during the last compressional episode, coeval with the inversion of the border faults of the Chelif Basin and the formation of subthrust structural closures in the underthrust foreland. The Pliocene is composed mainly of marine sandstones grading into blue marls and shallow marine sediments, alternating between sandstones and Algae limestones. The Quaternary deposits are made up of continental siliciclastic deposits (Fig. 2).

## 2.2. Geodynamic evolution and tectonic agenda

The Geodynamic evolution of the Chelif basin includes events of the Tethyan and Mediterranean domains. The opening of the Ligurian Tethys Ocean and coeval development of the northern passive margin of Africa occurred during the Triassic and Liassic. Since the Upper Jurassic the rotation of the African plate with respect to Eurasia induced a slow convergence between the two plates. This led to a progressive closure of the former ocean and to the formation of the circum-Mediterranean Alpine Mountains (Thomas, 1985). During the Late Cretaceous and until the Eocene, foreland inversions developed in the former rift basins of the Saharan Atlas due to a good coupling between the plate boundary and the African lithosphere at a time when the intervening oceanic domain was not yet fully subducted (Frizon de Lamotte et al., 2006; Bracene and Frizon de Lamotte, 2002; Roure et al., 2012).

Surprisingly, the Tellian allochthon consists of Upper Cretaceous to Eocene basal units derived from the distal part of the former passive margin of North Africa, with a basal decollement located in Triassic evaporites without any evidence for either Lower Cretaceous or Jurassic series in between (Fig. 3). The best interpretation here is to assume what has already been described for the Eastern Algerian and Tunisian Tell that salt canopies made up of Triassic series were already interstratified within the Cretaceous series of the passive margin (Vila et al., 1993; Masrouhi and Koyi, 2012, and references therein) thus, allowing a localisation of the main decollement along these interfaces during the



**Figure 3.** Regional structural cross-section of the Chelif Basin, outlining the Neogene flexural basin, the Langhian and Mesozoic series of the underthrust foreland, the Tellian allochthon, and the Tortonian–Messinian series of the thrust-top pull-apart basin and the main hydrocarbon kitchens and petroleum plays.



subsequent episodes of thrusting. Deep water turbidites of the Oligocene Numidian series were deposited both in the distal portion of the African margin and on top of the southward propagating Tellian tectonic wedge.

During the Neogene, the plate boundary between the Western Mediterranean and the Kabylides in the North and Africa in the South was a dominantly transform boundary where slab detachment and strike-slip faulting accounted for the lateral escape of the Gibraltar arc and Alboran block towards the West and the Tyrrhenian–Calabrian arc towards the East (Hsü, 1971; Olivier, 1984; Thomas, 1985; Carminati et al., 1998; Spakman and Wortel, 2004, and references therein). Due to strain partitioning, numerous episodes of transpression and transtension were recorded in the Chelif area, both in the Tellian allochthon and in the underlying foreland. The paroxysmal phase of thin-skinned deformation resulted in the thrust emplacement of the Tellian allochthon during the Lower Miocene. As a result, Middle Miocene series are currently located in three distinct tectonic positions in the vicinity of the Chelif Basin (Fig. 3): (1) in the autochthonous flexural basin where the Lower Miocene deep water turbidites rest directly on top of Upper Cretaceous black shales in Tiaret, (2) in the footwall of the Tellian allochthon where the Lower Miocene series still constitute a potential seal for the Mesozoic reservoirs of the subthrust prospects, and (3) on top of the Tellian allochthon in a piggyback position.

After the final emplacement of the Tellian allochthon on top of its foreland domain, an episode of transtension occurred along the plate boundary during the Tortonian and Messinian accounting for the formation of thrust-top pull-apart basins in the Chelif area (Roure, 2008; Roure et al., 2012) analogous to what has been described for the Vienna Basin at the junction between the Alps and the Carpathians (Sauer et al., 1992; Seifert, 1996) or in the Gulf of Paria between the Serrania del Interior in Eastern Venezuela to the West and Trinidad to the East (Lingrey, 2007).

Since the Pliocene, a good coupling between the plate boundary and the African foreland exists accounting for the transpressional inversion of former normal faults inherited from the Tethyan rifting in the underthrust African foreland. This new compressional episode has resulted in the formation of subthrust anticlines involving the Mesozoic parautochthonous series and in the refolding of the sole thrust of the overlying Tellian allochthon beneath the Chelif Basin. This can be shown in the eastern part of the Algerian Tell near Constantine (Vila, 1994) as well as in the tectonic windows of the Bibans and Ouarsenis Mountains (Mattauer, 1958) where the lower plate is currently exposed to the surface due to the large amount of tectonic uplift and erosion. Similar structures are observed in the Tempa Rossa and Monte Alpi fields of the Southern Apennines (Casero et al., 1991) and other nappe anticlines described in Northern Sicily (Casero et al., 1991; Roure et al., 2012). The tectonic studies show that the present deformation is mainly compressive with a NNW–SSE direction of shortening (Philip and Thomas, 1977; Meghraoui, 1982; Philip and Meghraoui, 1983; Meghraoui et al., 1986; Meghraoui, 1988; Meghraoui and Doumaz, 1996; Meghraoui et al., 1996; Boudiaf et al., 1998; Domzig et al., 2006; Yelles-Chaouche et al., 2006; Guemache, 2010; Meghraoui and Pondrelli, 2012; Derder et al., 2013; Abtout et al., 2014).

### 3. Samples and methods

A total of 290 samples have been analysed, 200 from the Middle Miocene series (with only 7 core samples), 75 samples from the Upper Miocene series (basal grey marls, dark-grey marls of Tripoli formation and gypsiferous marls), 6 core samples, 8 samples from the Upper Cretaceous series including 2 cuttings, and 7 samples

from the Oligocene series. Nine (9) samples from outcropping formations were collected along the northern and southern borders of the basin. The well samples (mainly Miocene and Oligocene) are from the relatively deep parts of the Neogene basin whereas the outcrop samples (mainly Upper Cretaceous) were taken from the Dahra Mountains in the North and from the La Mina and Ouarsenis Mountains in the South near the Tliouanet oil field. Most of the samples were collected by Sonatrach and its partners during internal exploration studies. Samples were analysed using a LECO analyzer SC144 after eliminating the carbonate fraction by acidification (50% HCL). A total of 58 samples with TOC (total organic carbon) values >0.5 wt.% (Table 1) were selected for Rock–Eval pyrolysis according to the standard technique proposed by Espitalié et al. (1977) using a Rock–Eval 6 apparatus (Behar et al., 2001). Rock–Eval pyrolysis is the most widely used method for screening the petroleum generation potential, thermal maturity and quantity and quality of organic matters in sedimentary rocks (Espitalié et al., 1977).

The well samples have been analysed at the Technology and Development Division of Sonatrach while the analyses of the outcrop samples were conducted at IFP-EN, France. The analytical technique consists of heating 100 mg of crushed rock to 600 °C at a temperature rate of 25°/minute in a helium atmosphere. Measured parameters include free hydrocarbons (S1) in mg HC/g rock, hydrocarbons cracked from kerogen (S2) in mg HC/g rock, carbon dioxide released from organic matter (S3) in mg CO<sub>2</sub>/g rock, and the temperature of maximum yield of pyrolysate (Tmax) (Barker, 1974; Espitalié et al., 1985, 1986). Only reliable samples were used for interpretation. The selection is based on the following geochemical parameter cut-offs: TOC > 0.5 wt.%, S2 > 0.2 mg HC/g dry rock (Peters and Cassa, 1994) and PI (Production Index) > 0.3 (Espitalié et al., 1985, 1986). In addition, 8 samples were submitted to palynofacies analysis and thin sections of kerogen were prepared. Transmitted white light microscopic technique was used for qualitative and quantitative examination of the kerogen components. In addition to the description of the facies, TAI (thermal alteration index) was determined for some samples. TAI is a numerical scale based on thermally induced colour changes in spore and pollen (Peters and Cassa, 1994) or liptinite. TAI is an arbitrary scale (from 1 to 4) that ranks the gradual change in colour and opacity of liptinite with temperature. TAI is equivalent to the lowest levels of organic maturity and is assigned to liptinite showing a greenish-yellow hue. TAI and maturity increase as the colour of liptinite progresses through pale yellow, yellow, amber, deep red-brown, and finally opaque black at TAI = 4 (Beardmore and Cull, 2001; Peters and Cassa, 1994).

We match the colour of the specimen under the microscope with a TAI standardized scale such as published by Correia (1967), Staplin (1969) and Jones and Edison (1978). Despite its limitations, TAI provides useful data when other maturity parameters fail (Peters and Cassa, 1994).

Chromatography analysis was performed on 5 rock extracts and 9 oil samples. Four rock extracts have been sampled in the 1584 m–1911 m depth interval from Oligocene marls in the W9 well in the Hellil area. Five different types of oil have been sampled in thin Oligocene sandstone layers at 1751 m and 1755 m in the W1 well in the Akboub region, in Middle Miocene sandstones of W4 well (El-Biod) at 1053 m depth, and finally from an Upper Miocene reservoir at 198 m–350 m in the W3 well. They were analysed using CPLC (capillary phase liquid chromatography) and CPGC (capillary phase gas chromatography) techniques.

The samples were extracted using dichloromethane as a solvent. The extracts were fractionated into saturated, aromatic and NSO (nitrogen, sulphur and oxygen) hydrocarbon classes using a column with a silica solid phase. The saturated fraction was analysed in an

**Table 1**

Geochemical parameters based on TOC cut-off &gt; 0.5% and S2 &gt; 0.2 mg HC/g TOC (most of the samples), from Rock Eval Pyrolysis and optical measurements.

Wells	Age	Lithology	Depth (m)	TOC	S2	HI	Tmax	TAI
Areas			Sample name	(%)	(mgHC/g rock)	(mgHC/TOC)	(°C)	
W1 (a)	Oligocene	Dark grey marls	1620	0.5	0.65	100		
			1750	0.5	0.40	90		
			1920	0.5	0.50	80		
W2 (a)	Oligocene	Dark grey marls	1751	0.5	0.40	77	368	1.5–2
			1913	0.5	0.29	55	389	
			2012	0.5	0.11	21	385	
W3 (a)	Upper Miocene (Messinian)	Gypsiferous marls	198	2.3	10.08	440	387	1.5
			202	0.8	0.94	117	377	
		Tripoli marls	346	1.0	1.19	113	428	
			350	1.4	2.25	164	421	1.5
			408	0.7	0.88	129	424	
W5 (a)	Upper Miocene (Messinian)	Grey marls	315	0.6	0.80	105	436	
			700	0.6	1.20	160	438	
	Middle Miocene	Grey marls	2490	0.6	0.23	40	439	
			2520	1.3	0.13	10	443	
			2850	0.6	0.13	22		
			3350	0.5	0.07	12		
			3590	0.7	0.35	42		
			3710	0.7	0.10	14		
			3730	0.5	0.09	17		
			3750	0.6	0.07	11		
			3810	0.6	0.21	33		
			3850	0.5	0.14	27	377	
			3910	1.2	1.28	109	451	
			3930	0.6	0.12	19	455	
			3950	0.8	0.22	26	454	
(W6) (a)	Middle Miocene	Grey marls	830	0.7	0.40	53		
			835	0.7	0.47	65		
			840	0.7	0.47	68		
			845	0.6	0.19	33		
			850	0.6	0.16	29		
			860	0.6	0.32	56		
			925	0.7	0.32	47	425	
			930	0.7	0.52	70	428	
			935	0.7	0.48	64	423	
			950	0.8	0.62	76	422	
W9 (a)	Oligocene	Deep dark grey marls	1584	0.9	1.28	141	439	1.5
			1693	0.8	1.19	149	437	
			1809	0.5	1.45	274	436	
			1966	0.6	0.41	63	439	
(W14) (a)	Upper Miocene (Messinian)	Dark grey marls	570	2.0	4.61	235	422	
			607	2.6	5.70	216	434	
		Grey marls	705	0.9	0.37	77		
			706.2	1.0	1.27	129	425	
			708.8	1.0	0.55	53	429	
			711	0.9	1.66	44	433	
			712	0.8	0.19	22	427	
W15 (a)	Middle Miocene	Dark grey marls	756	0.9	0.49	56	426	1.5
			1306	0.7	0.42	58	434	1.5
W16 (a)	Upper Cretaceous	Black shales	1070	0.9	0.05	6	599	
			1078	1.0	0.11	11	574	
Bouguirat (b)	Upper Cretaceous	Black shales	bg1	1.0	1.73	178	448	
			bg2	1.1	1.64	148	445	
Dahra Mountains (b)	Upper Miocene (Messinian)	Gypsiferous marls	Dhr1	1.2	3.04	211	421	
			Dh2	1.4	0.49	51	363	
		Dark grey marls	Dh3	1.3	5.00	566	426	
			Dh4	2.3	1.37	106	418	
	Burdigalian	Dark grey marls	Dhr5	8.2	0.97	12	574	
	Burdigalian		Dhr6	2.3	0.09	7	600	
	Upper Cretaceous		Dhr67	1.2	0.09	7	416	
	Upper Cretaceous		Dhr8	6.9	7.03	102	438	
	Upper Cretaceous		Dhr9	5.2	25.03	480	440	
Tliouanet (b)	Upper Cretaceous		Tt	3.0	10.14	339	440	
Relizane (b)	Upper Cretaceous		RZ1	0.6	0.16	29	422	

(a) Cuttings samples; (b) Outcrops samples.

Agilent\_7890 gas chromatograph (GC) that was equipped with an Agilent\_7683 auto-sampler coupled to a mass spectrometer (MS). The conditions of the GC equipment were as follows: the carrier gas was He at 1.2 ml/min in constant flow mode; the capillary column was a DB-5 Agilent (5% phenyl, 95% methylsiloxane,

30 m × 0.25 mm id; film thickness 0.25 mm); the temperature of the injector was 280 °C. The GC was programmed with an initial temperature of 70 °C (1 min) that increased to 170 °C at 20 °C/min and then to 310 °C at 2 °C/min (10 min). The transfer line temperature was 280 °C.

## 4. Results and interpretation

### 4.1. Lithology and thickness

The Upper Cretaceous series of the Tellian allochthon constitutes the substratum of the Neogene basin. Cretaceous outcrops are locally preserved in the vicinity of the Chelif Basin around the main Neogene depocenters either as well stratified Campanian outcrops or as hard blocks of Cenomanian limestones reworked in the shaly matrix by tectonic process along the sole thrust of the allochthon (Fig. 2). The lithology of the organic carbon-rich strata consists of mainly dark grey shales and marls. The same formation has already been described by Deveaux (1965) in the Mostaganem Plateau. It is composed of dark grey shale with an association of marly limestone.

Elsewhere in the Tahamda area (well W11), the Upper Cretaceous consists of laminated grey marls with 40% of carbonates intercalated locally with basalts and dolomites.

The Oligocene Numidian flysch crops out in the Tellian allochthon on both sides of the Neogene depocenters. However, it may be partly lacking beneath the main depocenters of the basin due to the listric geometry of the Miocene normal faults. It consists of grey to black marls (Fig. 2 and Table 1) deposited in a deep water environment indicated by the presence of pelagic foraminifera. Traces of anhydrite and pyrite are locally present, e.g. in well W11. Mineral carbon varies from 2 to 4% which gives an equivalent of 10–30% in carbonate composition. The bulk thickness varies between 0 and 500 m.

The Middle Miocene consists of grey marls with local presence of pyrite and glauconite. In the El-Biod area (well W5), the top of the formation is made up of thin ash layers (cinerites) between 1700 m and 1800 m depth (Fig. 5). Beyond 2900 m depth, the same marls are locally indurated and shaley with presence of pyrite (Fig. 5). As mentioned above, the Messinian shale contains soft grey marls interbedded with a diatomite formation containing itself a certain proportion of pyrite and glauconite, particularly in the northern part of the basin (Figs. 2 and 6) that record a lateral facies change to grey marls. The entire formation evolves vertically to gypsiferous marls and laterally to lithothamnium limestone on paleohighs (Thomas, 1985).

At outcrops, the Tripoli formation contains a set of laminated and grey marls at the base which evolves progressively to an alternation of marls, diatomite layers and locally inclusions of marly limestone (Perrodon, 1957; Mansour et al., 1994).

### 4.2. Organic geochemical characteristics and paleo-environment

#### 4.2.1. Organic richness (TOC)

Upper Cretaceous shales (Cenomanian to Campanian) have been sampled from outcrops along the northern and southern borders of

the Chelif Basin (Fig. 1b). Except for the Relizane area, their organic carbon content is fair to excellent (Peters and Cassa, 1994) where TOC varies from 1.5 to 6.9 wt.% (Fig. 4 and Table 1). TOC values vary from 0.6 to 3 wt.% in the Relizane and Beni Chograne Mountains near the Tliouanet field to the South whereas in the Dahra Mountains it ranges from 1.2 to 8.2 wt.% (Table 1).

The grey marls of the Oligocene Numidian series in the Hellil area (well W9) are characterized by low to fair organic carbon content, with TOC values ranging from 0.5 to 0.9 wt.% and a mean value of 0.7 wt.%. In the Akbou zone, 5 km farther to the North, core samples from well W2 display weak organic carbon with TOC values around 0.5 wt.% (Table 1).

In the El-Biod area which is considered as the deepest zone towards the East and in the Belkheir area in the western part of the basin, the thick series of Middle Miocene blue marls have generally TOC values less than 0.5 wt.%.

Only a few decimetre-thick beds record values within a range of 0.5–1.5 wt.% at two different depth intervals, i.e. 1825 m–3980 m and 830 m–950 m (Fig. 5 and Table 1). Furthermore, in the Ain Zeft area the TOC values of middle Miocene marls are less than 0.5 wt.% (Fig. 6).

The Messinian well samples have been taken in the north-eastern (El-Biod and Ain Zeft) and south-western parts (Belkheir and Fornaka) of the Chelif basin (Fig. 1b) at depths varying from 500 m to 750 m. The surface samples have been taken from Upper Cretaceous and Messinian outcrops in the Dahra Mountains (Fig. 1).

Three different layers of Messinian sediments have been sampled. From base to top they are 1) grey to dark-grey marls, 2) dark-grey marls either belonging to the Tripoli formation or to its lateral marly equivalent and 3) gypsiferous and sulphur-rich dark-grey marls. The basal layer is characterized by TOCs ranging from 0.5% to 1.3% in the W5 well to East (Fig. 5 and Table 1), 0.5% at W3 (Fig. 6) and 0.8–1% at W14 to the West (Table 1). The dark-grey marls which are intercalated with diatomite (Tripoli formation) have low to good organic carbon content in well W3 (Fig. 6) where the TOC varies from 0.7 to 1.4%. In the Dahra Mountains, samples of the dark-grey marls record good richness with two TOC values of 1.4 and 2.3% (Table 1). They are most likely the equivalent lateral facies of the Tripoli formation. Finally, the sulphur-rich gypsiferous dark-grey marls (yellow colour and sulphur smell in the field observed by Sonatrach's partner CNPC, internal report) is characterized by TOCs ranging from 0.8 to 2.3% in the Ain Zeft area (Fig. 6) and 1.2–1.3% in the Dahra area (Fig. 1b and Table 1). Except for one sample, the grey marls at the base of the Messinian are organically lean compared with the gypsiferous and Tripoli formations (Table 1).

#### 4.2.2. Paleo-environments and organic matter preservation

During the Upper Cretaceous and particularly during the Cenomanian–Turonian, a global rise of eustatic sea level occurred

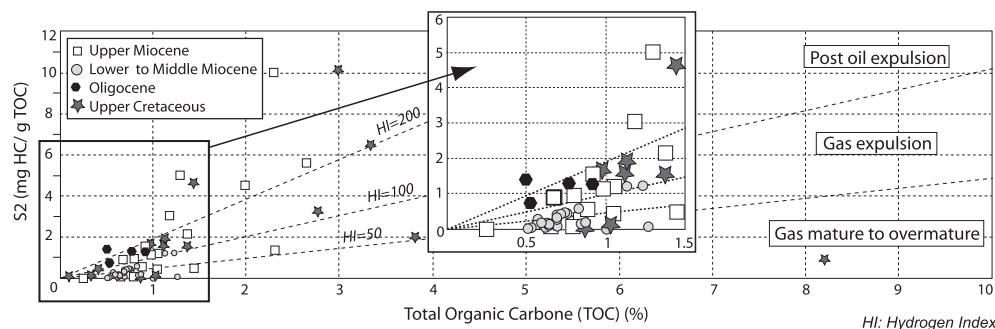


Figure 4. Maturity and expulsion indicators: S2/TOC diagram of different source rocks.

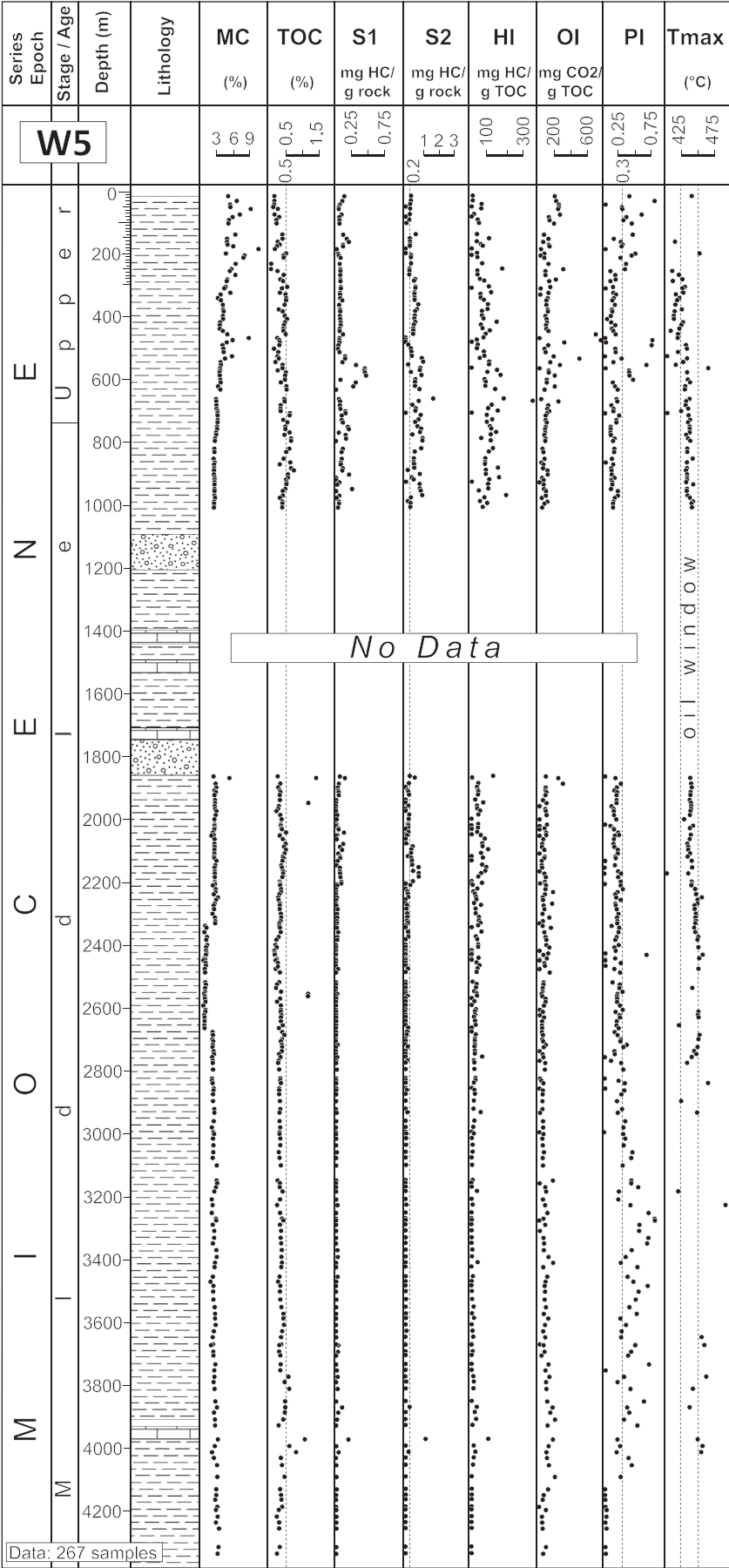


Figure 5. Geochemical log (Rock–Eval data) of the Miocene section (El Biod, Well W5).



resulting in a worldwide anoxic event coeval with the deposition of organic rich strata. This stratigraphic layer has already been studied in Northern Algeria (South-eastern Constantinois Basin) by Lüning et al. (2004). These authors defined a favourable depositional environment in terms of organic matter preservation. In the Chelif Basin, the facies of the sediments and the low OI recorded from the kerogen (less than 50 mg CO<sub>2</sub>/g TOC) (Table 1) are also indicative of an anoxic environment.

During the Oligocene, the depositional environment was mainly controlled by the geometry of the Maghrebides – Apenninic flexural basin which was probably disconnected from the Atlantic Ocean where up-welling could have occurred and would have renewed the anoxic zones with minerals that are necessary for the preservation of the organic matter. As in the Maghrebien to Calabre/Peloritan Alpine thrust belt, the Oligocene Numidian series are made up of deep water turbidites or flysch including hemipelagic mudstones (Thomas et al., 2010). They are locally characterized by the presence of pyrite and anhydrite accounting for a locally restricted environment. This depositional environment is assigned to both the slope and basin floor environments within a deep marine setting (Wezel, 1969; Stow et al., 1999; Riahi et al., 2007; Thomas et al., 2010). The geochemical parameters (TOC and S<sub>2</sub>, Table 1) of the well samples from the Hellil (well W9) and Akboub areas (wells W1 and W2) show a lateral variation from a confined to an open environment.

In the El-Biod area, the OI of the Middle Miocene series is moderate in most samples with values generally ranging from 10 to 200 mg CO<sub>2</sub>/g TOC and an average of 100 mg CO<sub>2</sub>/g TOC. This area constitutes the main depocenter of the basin with more than 5000 m thick Neogene deposits. Based on the presence of pyrite in the grey marls, its depositional environment was probably a deep water and anoxic environment. Nevertheless, the organic matter should have been preserved from oxidation. However, close to the basin borders, the OI is higher ranging from 100 to 300 at Belkheir and 200–400 mg CO<sub>2</sub>/g TOC at Ain Zeft (Fig. 6). This indicates an oxidation and thus a poor preservation of the organic matter as indicated in the graph and the picture of Figure 7 which is probably the main reason for the low HC potential of the analysed samples.

Basal Messinian marls (Fig. 2) are interbedded with thin diatomite layers in the so-called the Tripoli formation (Guido et al., 2007). This Messinian microflora has been studied by Mansour et al. (2008) in the SW Dahra Mountains whose planktonic neritic-oceanic species are more numerous than tychoplanktonic and benthic species. Generally, the planktonic organisms are abundant in the lower part of the section i.e. Early Messinian and their population decreases in the upper part (Late Messinian) to the benefit of tychoplanktonic or planktonic littoral species. This indicates a decrease of bathymetry from a deep marine environment with connection to the Atlantic ocean to an environment closer to littoral (Mansour et al., 2008). These deposits account for a deep marine environment coeval with the marine transgression characterized by the presence of glauconite. The lower part of this formation is characterized by a predominance of planktonic diatomites typical for cold water and thus indicating an upwelling of currents from the deep ocean (Mansour et al., 1994). This facies is also present in Sicily (Schaeffer et al., 1995) and represents a transitional facies between deep marine and evaporitic environment (Mansour et al., 1994).

Moreover, the preservation of laminated diatomites and the absence of burrows in the lower part are an indication of quiet and anoxic conditions (Mansour et al., 1994). These conditions could be favourable for preservation of organic matter (Mansour et al., 1994). The overlaying gypsiferous black marl unit is an indicator of a restricted environment coeval with a generalized regression and

salinity crisis (Rouchy et al., 2007) demonstrated by the deposition of algae limestone (Rouchy, 1981) and the precipitation of gypsum.

Based on well observations, the upper part of the Messinian contains white anhydrite or gypsum intercalated with dark-grey marls in the major part of the Chelif basin. As in Sicily (Hardie and Eugster, 1971), the gypsum is presented as selenite facies resulting in primary crystallization from a hypersaline environment. The occurrence of intercalated black shales in the same environment is due to sea level and salinity fluctuations. An almost similar environment is described by Guido et al. (2007) in southern Italy (Calabria and Sicily). Such a hypersaline environment allowed a good protection of the organic matter from biodegradation and oxidation.

#### 4.2.3. Type of organic matter

Biostratigraphic dating of the Upper Cretaceous source rock horizons (IFP-EN/Sonatrach unpublished data, Behar et al., 2006) have confirmed that the Upper Cretaceous organic carbon-rich strata are from the Cenomanian and Campanian. They were sampled in the northern and southern basin margins. The samples show a very low OI fluctuating from 5 to 60 mg CO<sub>2</sub>/g TOC and a Hydrogen index (HI) varying from 110 to 480 mg HC/g TOC (Figs. 7 and 8; Table 1). The OI varies generally from 50 to 100 mg CO<sub>2</sub>/g TOC. Although the HI/OI plot indicates a Type I organic matter, the HI/Tmax plot rather indicates a Type II marine kerogen mixed with Type III (continental) and/or Type I in few samples (Figs. 7 and 8). The same formation has also been studied in north-eastern Algeria by Lüning et al. (2004) who determined only Type II kerogen. Therefore, the Type I and Type III signatures are probably very limited in this formation. The majority of the samples are aligned along the Type I and/or Type II kerogen (Figs. 7 and 8) and only one sample plotted on the Type IV line (Fig. 8).

The Oligocene samples present an OI varying between 180 and 220 mg CO<sub>2</sub>/g TOC and reach a maximum of 350 while the HI values vary from 50 to 92 mg HC/g TOC, positioned below the Type III line (Fig. 8). In the plot HI versus Tmax which is usually used to classify maturity and type of organic matter (Tissot and Welte, 1984; Espitalié, 1986), the samples are aligned along the Type II kerogen although one sample is located in the Type IV kerogen area (Fig. 7). Optical analysis using transmitted light on microscope reveals amorphous organic matter (Fig. 8) in all samples. This result is consistent with the HI/Tmax plot classification indicating a tendency for Type II kerogen.

The Middle Miocene marls of the El-Biod area show very low free hydrocarbons. The residual potential yields also a weak S<sub>2</sub> less than 0.2 mg HC/g dry rock in most of the samples. At shallow depths, the HI remains very low even though the Tmax values are lower than 430 °C. HI varies globally from 20 to 80 mg HC/g TOC while OI varies from 10 to 200 mg CO<sub>2</sub>/g TOC (Fig. 5). In the Ain Zeft area (well W3), TOC is less than 0.5% indicating that the pyrolysis parameters are not reliable (Fig. 6). In the HI/Tmax plot (Fig. 7), the majority of samples are positioned in the Type IV zone. The high concentration of oxygen is consistent with the optical analysis which reveals the presence of inert organic matter in the Middle Miocene sediments. Moreover, terrestrial material might have been transported by the rivers to the ocean where probably turbidite flows had been deposited in the deep marine environment, given the proximity of the hinterland to the deep basin.

As specified above, the Upper Miocene (Messinian) is composed of grey marls at the base, the Tripoli formation (alternation of thin layers of diatomite and dark-grey marls) and gypsiferous dark-grey marls at the top. The majority of samples show poor residual potential (S<sub>2</sub> < 2.5 mg HC/g dry rock, Peters and Cassa, 1994) where the S<sub>2</sub> varies from 0.7 to 1.5 mg HC/g dry rock (Table 1). Nevertheless, 4 samples have somewhat higher values varying from 3 to

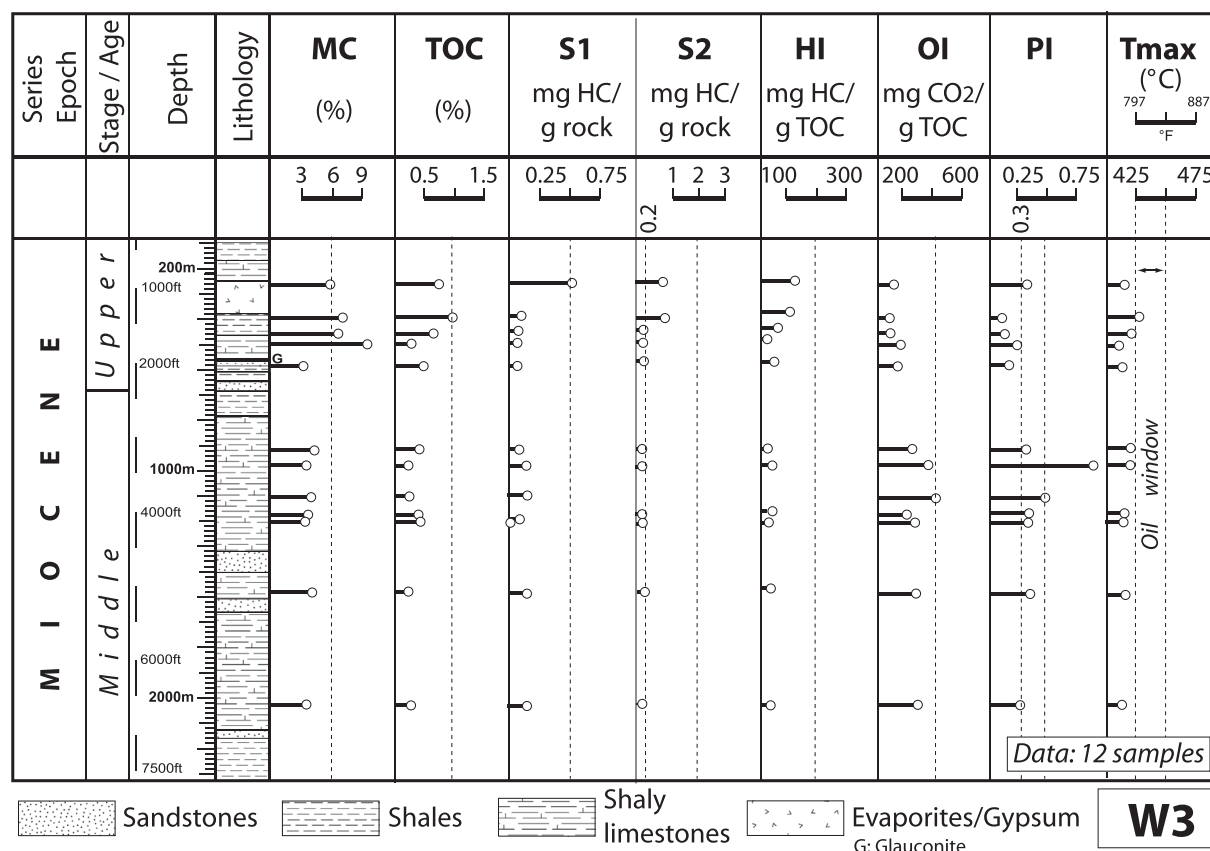


Figure 6. Geochemical log (Rock–Eval data) of the Miocene section (Ain Zeft field, Well W3).

10 mg HC/g dry rock. In the Ain Zeft area, only two samples display fair to excellent HC potential (HI = 211 and 566 mg HC/g TOC). The rest of the samples are characterized by relatively low HI, generally lower than 200 mg HC/g TOC.

Most samples from the El-Biod area (well W5) display a high OI (200–600 mg CO<sub>2</sub>/g TOC) and a low to fair HI varying from 10 to 200 mg HC/g TOC and averaging 100 mg HC/g TOC (Fig. 5). However, at Fornaka (well W14) in the western part of the basin HI varies from 29 to 75 mg HC/g TOC between 830 m and 950 m depth and OI from 100 to 200 mg HC/g TOC (Table 1) which reflects a high proportion of oxygen in the organic matter.

In the HI vs Tmax diagram (Fig. 7), samples are outside the Type II kerogen area except for one sample which is characterized by a high petroleum potential of HI = 566 mg HC/g TOC. There are two distinct populations: the first is positioned in the oxidized and/or matrix retention zone and the second population is inside the Type III area. However, regarding the high potential recorded in some samples either along the southern border (Dahra outcrops) or in the Ain Zeft wells, the organic matter can be classified as Type II marine organic matter with contributions of terrestrial humic organic matter. The latter may be explained by the low values of HI at almost the same depths as the gypsiferous marls (Table 1).

Both basal grey marls and marls of the Tripoli formation may be classified geochemically as a mixture of Type II and III (Figs. 7 and 8) due to the proximity of mountains, as Chelif is a typical intra-mountain basin. Moreover, part of the organic matter might have remained in place and consequently been altered (Fig. 7).

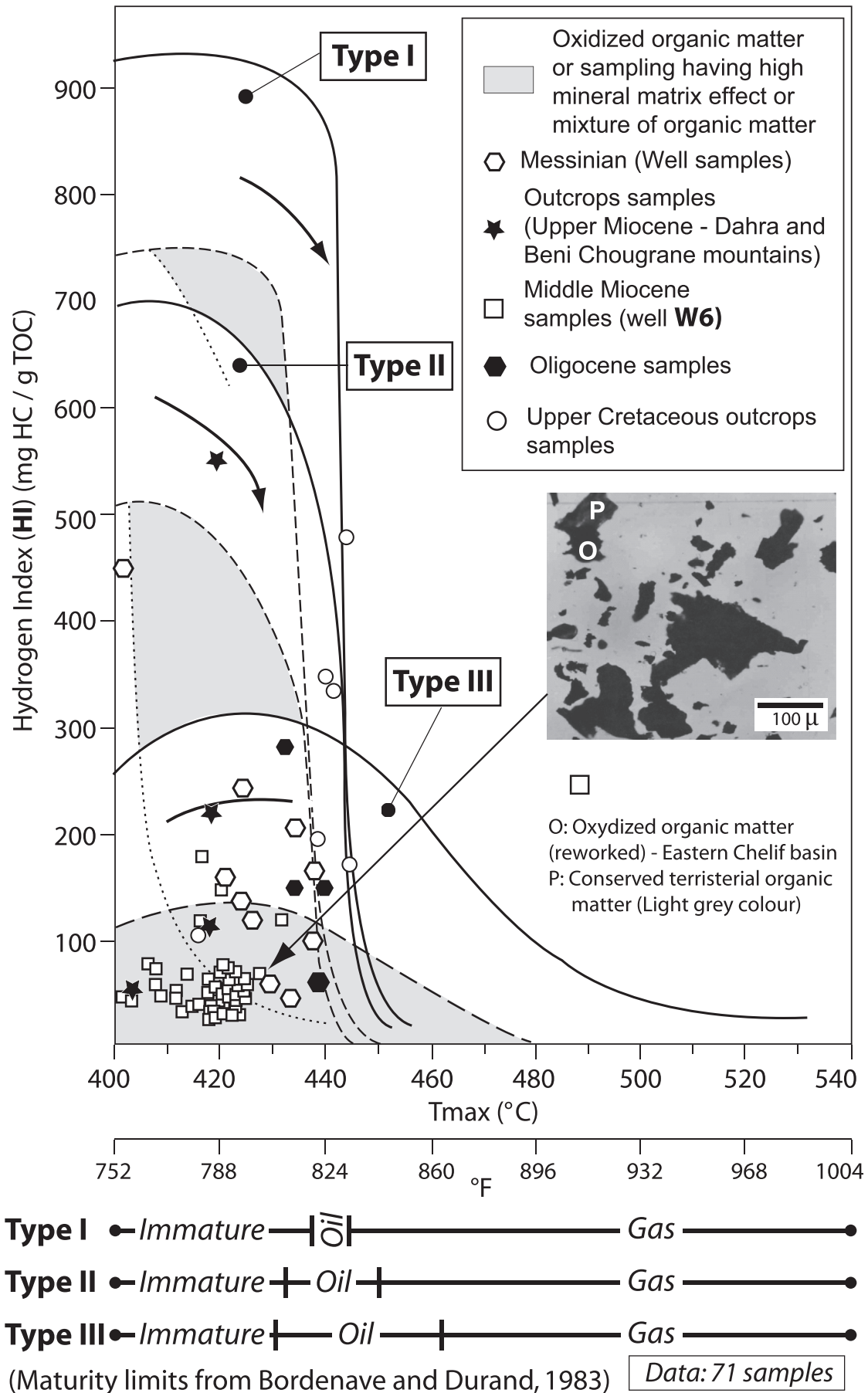
Furthermore, the gypsiferous to anhydrite dark-grey marls of the top Messinian occurred in an evaporitic and restricted environment. In such an environment, the high sulphur content (>2%) and the geochemical characteristics of the rock extract (next

chapter) argue for a Type II-S organic matter. Sulphur-rich source rocks are generally deposited in evaporitic and/or anoxic carbonate platform environments (Schaeffer et al., 1995; Di Primio and Horsfield, 1996). The equivalent formation has also been studied and described in southern Italy (Calabria and Sicily) by Schaeffer et al. (1995), where it has been classified as Type II-S (Orr, 1986; Eglinton et al., 1989).

#### 4.2.4. Thermal maturity

Tmax and TAI (Thermal Alteration Index) can be used as indicators for maturity. In the Upper Cretaceous organic carbon-rich layers, Tmax varies regionally from 415° to 460 °C. Some outcrop samples display high residual potential with HI varying from 102 to 480 mg/g TOC and Tmax from 438 to 448 °C. However, at Mozaia near Akboub the organic matter is characterized by low HI values varying between 5 and 12 mg HC/TOC and very high Tmax values ranging from 574 to 599 °C (Table 1) corresponding to the dry gas window. The maturity of the Upper Cretaceous shale which is the deepest formation reached by the wells is less variable. The majority of the samples plot in the oil zone corresponding to a Tmax of 438–448 °C (Fig. 7). Some outcrop samples display high residual potential with HI values varying from 102 to 480 mg HC/g TOC and Tmax from 438 to 448 °C (Fig. 7 and Table 1). The evolution of TOC in the S2/TOC plot is partly due to the advanced thermal maturity where most samples reach the post oil expulsion state (Fig. 4).

In the Hellil area (central part of the basin), the Oligocene samples display Tmax values ranging from 432 to 440 °C at depths between 1584 m and 1966 m (Table 1). In contrast, in the Akboub area the recorded values are lower than 430 °C even at relatively great depths between 1751 m and 2012 m. The TAI (Thermal



**Figure 7.** The Hydrogen index (HI) versus Tmax (maximum temperature pyrolysis) plot for Upper Cretaceous, Oligocene and Miocene samples from wells and outcrops.

Alteration Index) is about 1.5 which is an additional indication of an immature state (Table 1).

Burdigalian dark-grey marls were sampled in the Dahra outcrops. They have been found only along the basin borders and their presence in the deep basin area is unlikely. They are represented by two samples presenting a poor residual potential (eg. Peters and Cassa, 1994), with S2 values of 1 and 0.1 mg HC/g TOC which correspond to HI values of 7 and 12 mg HC/g TOC respectively. The sample of residual potential that is higher than S2 >0.2 mg HC/g TOC shows a Tmax of 574–600 °C (Table 1) which indicates late gas window.

A large number of Middle Miocene samples are from the W5 well in the El-Biod area (267 including Upper Miocene samples) that record mainly TOCs lower than 0.5% and S2 lower than 0.2 mg HC/g TOC (Fig. 5). Only three samples have reliable TOC, S2 and Tmax data positioned at depths of 2490 m, 3910 m and 3950 m. They show Tmax values of 439 °C, 451 °C and 454 °C. At Belkheir in the western part of the Chelif basin, Tmax values are ranging from 422 to 428 °C. The residual potential S2 is lower than 0.5 mg HC/g dry rock. These values do not fit the Tmax data (Table 1) in terms of maturity. Close to the northern border of the basin in the Noisy area, Tmax varies from 426 to 434 °C and TAI is about 1.5 with a weak petroleum potential of 0.4–0.5 mg HC/g dry rock (Table 1). The Middle Miocene series is characterized by low generative potential and is organically lean. It contains only a few thin organically rich layers. Except for the El-Biod area where few Tmax values are reliable, the same parameter is low elsewhere (<430 °C) most probably measured from deformed and/or flat S2 peaks (the actual pyrograms are no longer available). The low values are either due to the matrix effect for TOC <1% which is the case in the El-Biod well (W5) or due to oxidized organic matter as in Belkheir where OI varies from 100 to 300 mg CO<sub>2</sub>/g TOC.

El-Biod is the deepest zone of the basin where the bottom of Middle Miocene marls have not been reached by any well with a maximum depth of 4300 m (Fig. 5). The organic matter samples that reached the oil window are found at about 2500 m but these values most likely reflect a frozen kitchen where the maximum burial is obviously larger. Samples in the gas window are found at 3900 m (Fig. 5). However, both in Noisy (well W15) or Belkheir (well W6) Tmax values are abnormally low corresponding to a weak residual potential of S2 < 0.7 mg HC/g dry rock (Table 1). Such values are indicators of unreliable S2 peaks which do not allow for accurate Tmax measurements by the pyrolyser. This is probably not only due to maturity but also due to matrix retention and alteration of the organic matter either during sedimentation or during storage, considering the high OI in some areas. However, in the case of a pure thermal effect (absence of any other physico-chemical effects) the transformation ratio TR (TR = initial HI – residual HI/initial HI) which can be considered as an efficient thermal indicator is estimated to be 80–90% (with an initial HI of 566 mg HC/g TOC) in both areas (Noisy and Belkheir) indicating condensate to gas window.

As presented in Figure 4, most samples of the organic-rich Messinian are located in the area of high maturity and hydrocarbon expulsion. However, except in the El-Biod (well W5) where Tmax values are 436–438 °C indicating an oil window the rest of the Messinian samples exhibit Tmax values lower than 430 °C (immature state, Fig. 7 and Table 1). In the W3 well the TAI confirms the low maturity. Moreover, most samples are aligned with a type III to mixed type II/III organic matter and some are found to be subjected either to oxidation during the sedimentation and/or during storage but also to matrix retention (Fig. 7). Only two samples from the Dahra Mountains (Table 1) may be mature considering the nature of the organic matter (Type II-S). They belong to the sulphur-rich gypsiferous marl which generates oil at lower Tmax (>420 °C) (Bordenave and Durand, 1993). Heavy

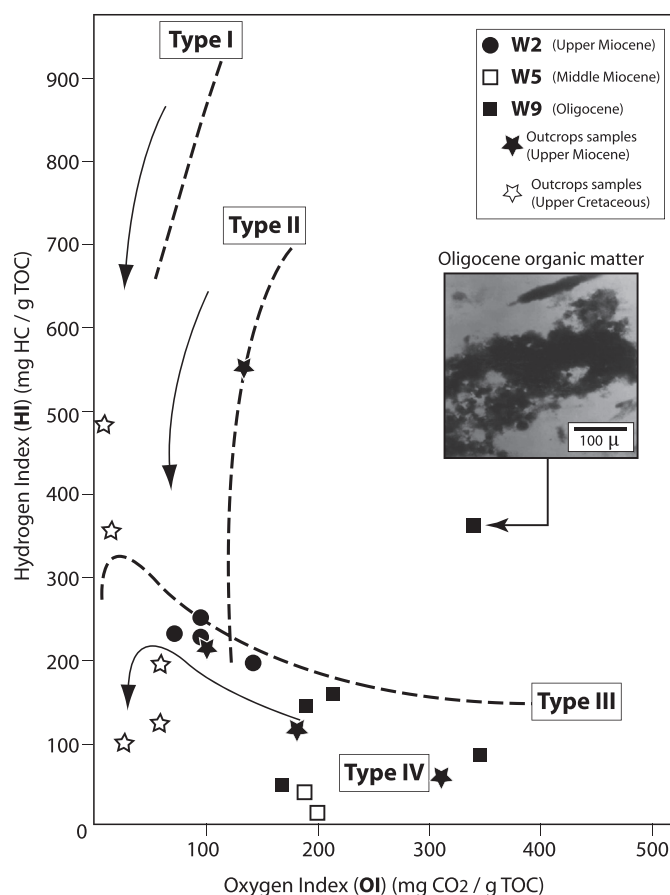


Figure 8. The Hydrogen index (HI) versus Oxygen index (OI) plot for Upper Cretaceous and Miocene samples from wells and outcrops.

sulphured oil seeps are observed in the same layer in the Ain Zeft area (small oil field). Sulphur-rich marine source rocks have been found to generate sulphur-rich heavy oils at low maturities (Orr, 1986; Di Primio and Horsfield, 1996; Lehne and Dieckmann, 2007).

#### 4.3. Effective source rocks and hydrocarbon potential

As in the circum-Mediterranean or Tethyan Mesozoic margins and particularly in Northern Algeria, the Upper Cretaceous black shales (Cenomanian–Turonian and Campanian) represent excellent source rocks since they occurred during numerous global anoxic events (Lüning et al., 2004). They are characterized by fair to high residual potential and most samples are found to be at the onset of oil generation.

In the Chelif basin and its Tellian borders, most Messinian samples show good geochemical characteristics. The Messinian contains three organic-rich layers amongst which the dark-grey marls of the Tripoli formation and the gypsum marls. The former were deposited during a maximum flooding event (Zhang et al., 2009) after the maximum transgression of the Tripoli Sea while the latter were deposited in a confined and hypersaline environment. However, the entire stratigraphic level is found to be immature in a large part of the Chelif basin due to insufficient burial to reach the required temperature of oil generation. Nevertheless the Ain Zeft field is an indication of a generation of hydrocarbons from mainly gypsum marls which contain type II-S organic matter.

The Middle Miocene cannot be considered as a potential source rock because its organic-rich layers are thin and preservation of organic material is fair to low. Moreover, most samples present low



TOC values (Figs. 5 and 6). This is mainly due to dilution of the organic matter especially for the Middle Miocene because of the high sedimentation rates recorded in the deep part of the basin. The Oligocene dark grey marls have almost identical characteristics except in the Hellil area (well W9) where few samples present fair organic carbon content and relatively good residual potential.

Although the Burdigalian series presents fair to excellent organic carbon content, the limited number of samples and the absence of data related to the conservation of its organic matter prevent us to consider it as a principal source rock. Moreover, its regional distribution is restricted to the northern border of the basin.

#### 4.4. Petroleum geochemistry

##### 4.4.1. Liquid chromatography analysis (CPLC)

The normalized percentage of the aliphatic, aromatic and NSO fractions of each sample of rock extract and oil are plotted in a ternary diagram (Fig. 9). Four rock extracts from grey Oligocene marls that have been sampled in the western part of the basin (W9) are characterized by high content of aliphatic hydrocarbons varying between 55 and 70% whereas the proportion of aromatic and NSO compounds is rather low (30–45%). Two oil samples from Oligocene sandstones of the W1 well were also analysed and present different proportions of NSO and aliphatic hydrocarbons. The first sample shows 62% of aliphatic hydrocarbons, 15% of aromatics and 36% of NSO compounds. The second sample displays almost the same proportion of aromatics but a higher NSO content (54%) and less n-alkanes (45%) (Fig. 9). The Middle Miocene oil sample from the W4 well (El-Biod) contains 51% of HC saturates, only 9% of aromatics and 40% of NSO.

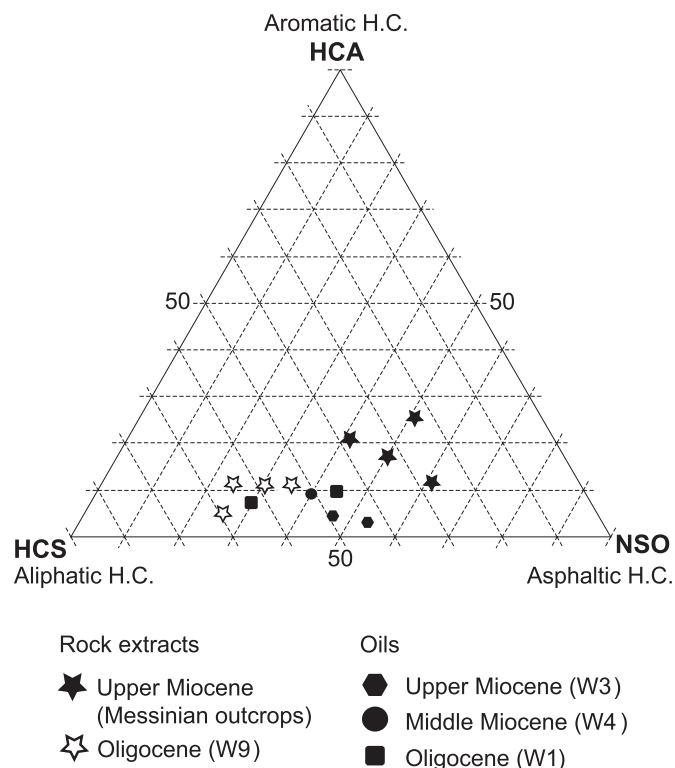
Three Messinian rock extracts are characterized by their higher aromatics and NSO content which could be an indication of low maturity.

Finally, two oils were sampled from Upper Miocene reservoirs at 198 and 350 m depth in the W3 well showing moderate proportions of aliphatic (42–50%), low aromatic hydrocarbons (3–5%) and higher NSO compounds (45–52%) (Fig. 9). Oils and rock extracts are most probably sourced from marine organic matter considering the lower proportions of aromatics.

##### 4.4.2. Normal alkanes and isoprenoids (gas chromatography)

The Pristane/Phytane (isoprenoids) ratio Pr/Ph is often used as an indicator of redox conditions in the sediments but should be interpreted carefully due to the interference with other factors such as the origin and maturity of the organic matter (Waples and Machihara, 1991; Peters et al., 2005). According to several authors (Brooks et al., 1969; Didyk et al., 1978; Peters et al., 2005),  $Pr/Ph < 1$  indicates reducing conditions, while  $1 > Pr/Ph < 3$  reflects oxic conditions. Ratios  $> 3$  are related to terrestrial sediments (Hunt, 1979). The  $Pr_{nC17} - Ph_{nC18}$  graph (Fig. 10, from Lumbach et al., 1975, in Chaouche, 1992) is used to define maturity and type of organic matter of the source rock that has generated the oils and extracts. They have been analysed by gas chromatography (GC).

Three rock extracts from Oligocene marls have been sampled from the W9 well in the Hellil area of the western part of the Chelif basin within the depth interval of 1584–1911 m. Two samples from 1693 m to 1911 m depth yield values of  $Pr/nC17$  between 0.47 and 0.54 and  $Ph/nC18$  between 0.44 and 0.51 (Fig. 10). These samples plot in the zone of sapropelic oil-prone kerogen (type I or type II) whereas the third sample from the same well at 1584 m depth shows higher  $Pr/nC17$  (0.62) and lower  $Ph/nC18$  (0.34) that plot in the Type III zone (humic organic matter) (Fig. 10). In the W4 well (El-Biod area), a sample yielding  $Pr/nC17$  and  $Ph/nC18$  values of 0.64 and 0.61 is positioned in the sapropelic kerogen zone at lower



**Figure 9.** Ternary diagram showing the gross composition of crude oils and rock extracts: aromatic hydrocarbon, saturated hydrocarbons and resins & asphaltenes or NSO (Nitrogen, Sulphur and Oxygen) compounds (wt. %) for oils (from reservoir) and rock extracts (from source rock).

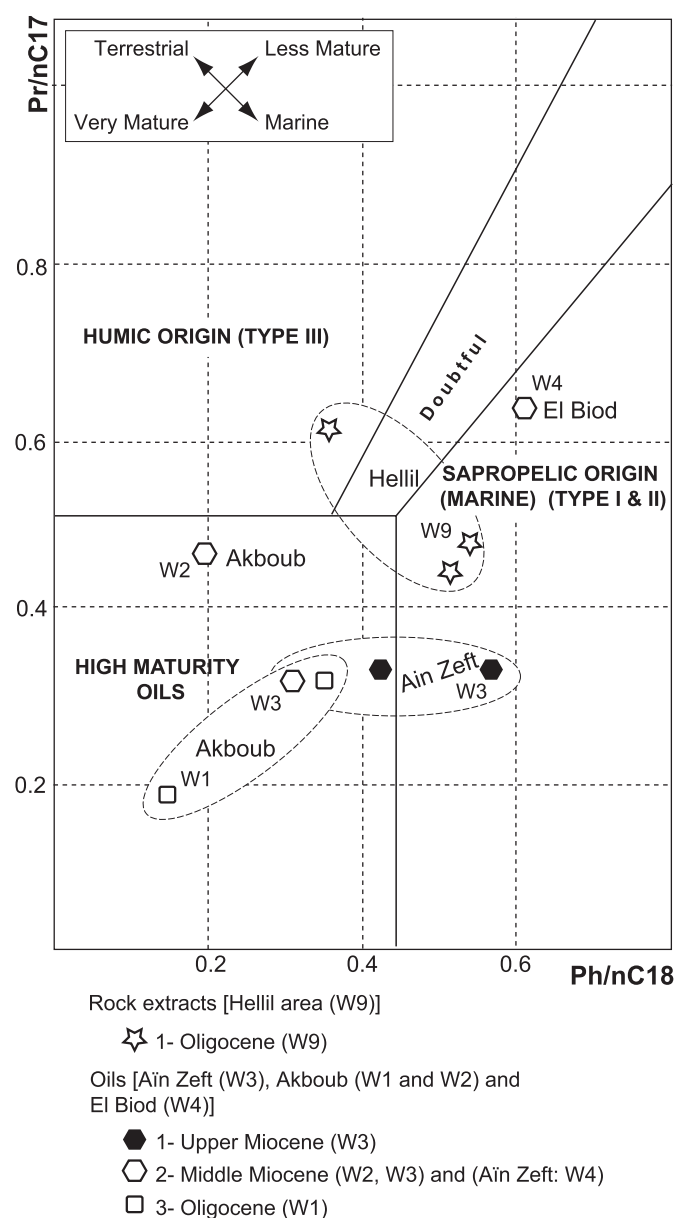
maturity (Fig. 10). Two other oil samples issued from Ain Zeft field (well W3) present a similar  $Pr/nC17$  ratio of 0.33 and  $Ph/nC18$  ratios of 0.42 and 0.53 (Fig. 10). While the sample of higher  $Ph/nC18$  is plotting in the sapropelic kerogen zone, the second plots in the higher maturity zone but no conclusion can be drawn as to the origin of the organic matter (Fig. 10).

Along the southern border of the Chelif Basin in the Tliouanet field, numerous samples have been analysed with GC as part of an internal study conducted by IFP-EN and Sonatrach (Behar et al., 2006) of which we only show the most representative ones. The higher proportion of n-C14 to n-C21 in the chromatogram indicates a higher maturity of the oil (Fig. 11a). Alternatively, the regular decrease of the peak height of n-C30 to n-C19 is also an indication of a marine environment from which the oil has been generated. Its  $Pr/Ph$  value of 1.6 is an indication of a highly reduced environment (Fig. 11a). The rock extract shows the same n-alkane distribution in the chromatogram as the Tliouanet oil sample. There is a predominance of n-C15 to n-C21 components indicating relatively advanced maturity (Fig. 11 b).

The oil sample of Ain Zeft field (well W3) and the rock extract from the Messinian shales (outcrops) have also been analysed with gas chromatography (GC). The chromatograms yield a distribution of C15+ n-alkanes that can be used for correlation. The Ain Zeft oil sample displays a high concentration of C21–C35 with a predominance of even number n-alkanes and low  $Pr/Ph$  ratios (0.16) (Fig. 11c).

The chromatogram of the Messinian extract from outcropping gypsiferous marls shows a similar n-alkane distribution with a predominance of even number components and a low  $Pr/Ph$  ratio (0.5) (Fig. 11 d). Theoretically this is an indication of a source rock deposited in a highly reducing evaporitic environment. As for the oil sample, the n-alkane pattern shows a high proportion of long-





**Figure 10.** Plot of the phytane to n-C18 alkane (Ph/n-C18) versus pristane to n-C17 alkane (Pr/n-C17) (graph model from Lumbach et al., 1975, in Chaouche, 1992). Are represented samples of oils and rock extracts belonging to the Oligocene and Miocene formations.

chained saturates (C21–C35). The same chromatogram displays a high proportion of small peaks between the major n-alkanes peaks (Fig. 11d). According to Fingas (2010), these small peaks are called unresolved complex mixture or UCM. It is an aggregate of largely unresolved peak of alkane origin.

#### 4.5. Thermal modelling

##### 4.5.1. Input data

The basin modelling software used in this study is Genex4 (Beicip-Franlab, 1995). The geological model involves lithostratigraphy, tectonics and geothermal history in relationship with the geodynamic evolution of the basin. Physico-chemical concepts and the required geological and geochemical data are used to reconstruct burial and thermal history of the basin, the maturity of source rocks and petroleum generation and expulsion

(Tissot and Welte, 1984; Ungerer et al., 1990). Conversion of kerogen to hydrocarbons is driven by temperature and time-dependent kinetic cracking reactions (Tissot and Welte, 1984).

**4.5.1.1. Geological data.** The required data are geological ages, lithologies and depths of each formation including unconformities expressed as missing section. The first three parameters are issued directly from well data while the last one is assessed either by thermal indicators such as vitrinite reflectance, apatite or zircon fission track measurements or shale porosities.

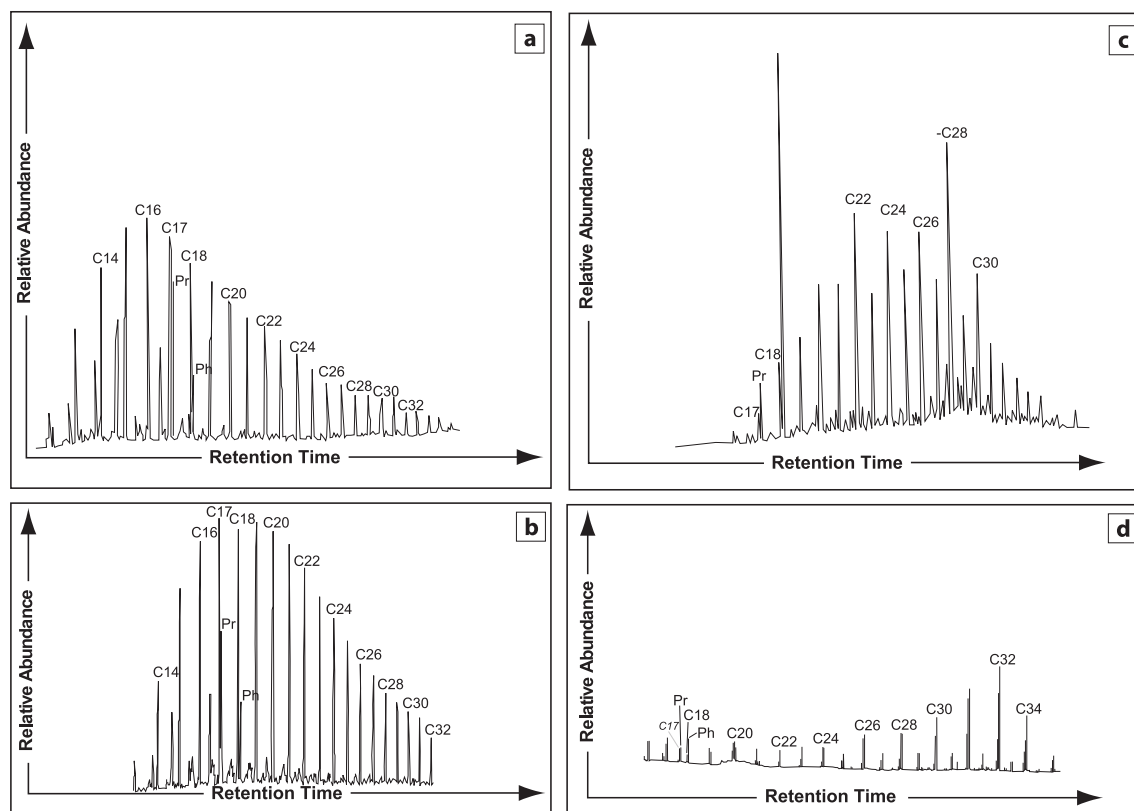
The total depths for the W5 and W11 wells are 4350 m and 2650 m. The dominant lithology used in the two wells is marl while the other lithofacies vary from sandstones to limestones and partly evaporites for the Messinian strata.

The missing section of the upper part of the Messinian and Plio-Pleistocene in the W5 well is estimated to be 600 m from geometrical extrapolation using seismic profiles. The parautochthonous Mesozoic and Paleogene strata which constitute the substratum of the Neogene basin are included in the modelling of well W11. Uncertainties related to the unconformities between Turonian and Oligocene and between Oligocene and Neogene sediments render the estimation of missing sections difficult. The erosion resulting from the Quaternary inversion is particularly important for the Miocene source rocks and therefore constitutes a major constraint to take into account. The burial amount in the studied wells is based on assumptions of the erosion during the upper part of the Upper Cretaceous and the Paleocene. It is calculated by extrapolating the thickness of neighbouring Tellian parautochthonous units. Polvéche (1960) estimated the initial thickness of Paleogene series from outcrops in the Ouarsenis Mountains. The Paleocene is represented by marls and marly limestones with an average thickness of 100 m. It is overlain by Nummulitic limestones and black marls of Eocene age that vary in thickness from 50 to 150 m. The Oligocene is made up of thick series of black shales and alternating grey marls with thin layers of limestone with an average thickness of 500 m estimated from outcrops and wells.

In the absence of paleo-bathymetric data, water depth as well as sea-level variations through time were neglected in the modelling.

**4.5.1.2. Geothermal context and boundary conditions.** The thermal history of a sedimentary basin is governed by (1) basal heat flow from the asthenosphere, (2) the radiogenic heat produced in the crust and (3) thermal advection through regional water flow. The heat flow variation is governed by the nature of the lithosphere and its thickness variation as a function of the geodynamic setting. 1D thermal modelling in thrust belts remains a difficult task due to the spatial and temporal changes in the lithosphere and the evolution of the crustal architecture. Rifting and passive margin development are usually characterized by a relatively high thermal regime whereas orogenic paroxysms are likely to account for the development of a thicker crust. The latter also have a thick lithospheric root and most foreland flexural basins are instead characterized by relatively low heat flows. Alternatively, post-orogenic slab detachment and rise of an asthenospheric diapir beneath the offshore Algerian basin may have temporally restored an elevated heat flow in the vicinity of the Chelif Basin during its Upper Miocene peak of subsidence.

Another problem with 1D modelling is that they have difficulties to account for tectonic duplication. Before the Langhian, the Tellian allochthon records a completely different thermal evolution compared with the underthrust foreland. The two domains were ultimately superposed with only minor subsequent tectonic contraction.



**Figure 11.** Gas chromatograms of saturated fractions showing the distributions of n-alkanes (nC14 + saturates) of selected rock extract and oil samples. (a) Oil fraction from Upper Miocene reservoir (Tliouanet field). (b) Upper Cretaceous hydrocarbon extract (Chelif basin). (c) Oil fraction from Upper Miocene reservoir (Well W3; Ain Zeft area). (d) Messinian hydrocarbon extract of Messinian gypsiferous marls exposed in the Ain Zeft outcrops.

Today, the North Algerian Tellian Atlas displays a normal crust with a thickness between 30 and 40 km (Marillier and Mueller, 1982; Thomas, 1985).

According to Louni-Hacini et al. (1995), Neogene volcanic activity produced calc-alkaline to shoshonitic andesites and dacites in the Sahel areas of Oran and M'Sirda and alkaline basalts in the Tafna valley. Seventeen new  $^{40}\text{K}/^{40}\text{Ar}$  ages (Louni-Hacini et al., 1995) indicate that these volcanics were emplaced during two distinct periods between 11.7 and 7.2 Ma and around 4 Ma. All andesites and dacites were emplaced during the first period and their trace element characteristics are typical of subduction- and/or collision-related magmatism. During the Late Pliocene and Quaternary, volcanic activity occurred in the Moroccan Middle Atlas and in the area of Oran in Algeria (Fig. 1a).

In the Tellian thrust belt, the heat flow increases rapidly towards the Mediterranean Sea. Its overall pattern is comparable with that measured in other Tertiary fold belts (Takherist and Lesquer, 1989). According to these authors, the present day heat flow varies from 80 mW/m<sup>2</sup> in the South to more than 100 mW/m<sup>2</sup> near the offshore.

Present day geothermal gradients have been calculated based on corrected BHT and DST temperatures from wells. They vary from 30 to 35 °C/km to more than 50 °C/km (Fig. 12). Two hotter zones are found. They are in the central part of the Chelif Basin, possibly due to the local occurrence of Neogene diapirs remobilizing the Triassic salt of the Tellian allochthon (Fig. 3) and in the coastal zone near the Gulf of Mostaganem in the vicinity of the neoformed Neogene oceanic lithosphere of the offshore Algerian Basin.

Regionally, the present day heat flow varies from 50 to 85 mW/m<sup>2</sup> (Fig. 13a). The heat flow model is variable through geological time in order to account for geodynamic processes. During the

main episodes of tectonic contraction from Upper Cretaceous to Lower Miocene, the mean heat flow value is estimated to 50 mW/m<sup>2</sup> (Fig. 13a). However, we assume a higher heat flow in the deep parts of the Chelif basin due to volcanic activity since the onset of slab detachment and accelerated subsidence during the Tortonian–Messinian (Fenet, 1975; Bellon and Brousse, 1977; Ait Hamou, 1987; Maury et al., 2000) which is estimated at 90 mW/m<sup>2</sup> (Fig. 13a). Finally, present day heat flow has been determined from the geothermal gradient and thermal conductivities of the sediments. Despite a decrease due to the Quaternary tectonic inversion and probable lithospheric thermal cooling it is still high, particularly in the deep parts of the Chelif basin. The reverse shift of heat flow between bottom basement and bottom sediments during the Miocene and Plio-Pleistocene time (Fig. 13a) is most likely due to the blanketing effect caused by high sedimentation rates (Fig. 13b).

**4.5.1.3. Geochemical input data.** Simulating the generation of hydrocarbons from organic matter requires measurements of organic richness, thickness, type and maturity of the organic rich layers. In the W5 well (El-Biod) from the eastern part of the Chelif Basin, two source rocks are considered for the simulation: the Middle Miocene organic-rich layers and the Messinian shales. Initial TOCs of 2% and 4% are attributed respectively to these horizons. The T<sub>max</sub> data are used for maturity calibration. Bulk kinetic parameters of a standard Type II organic matter have been used for the simulation. Since a Type II-S kinetics is not implemented in the software, the default standard Type II is also used for the gypsiferous Messinian formation.

In well W11 which is located in the Tahamda area in the western part of the basin, two principal source rocks were considered: Cenomanian and Messinian shales with 8% and 4% TOC

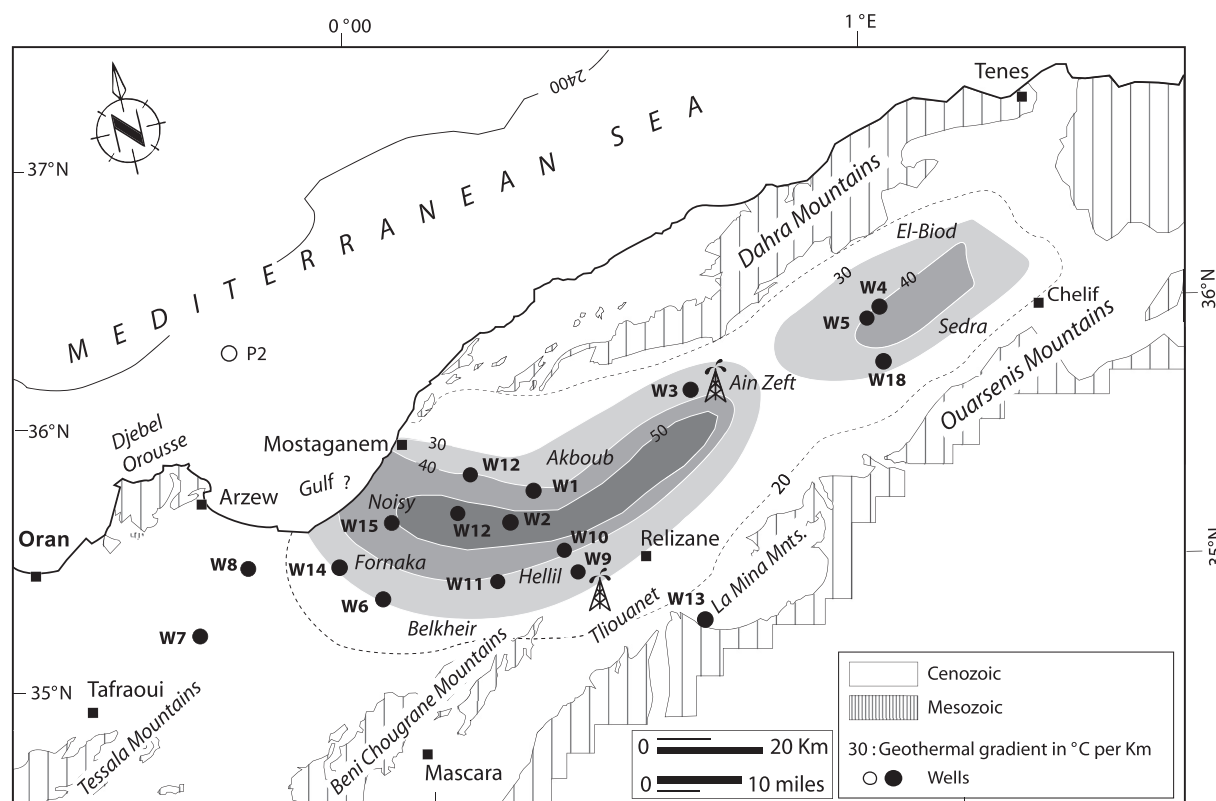


Figure 12. Regional geothermal gradients map (GG) (°C/Km).

respectively. The Langhian and Oligocene series are also included as secondary sources with only 1.5% and 2% TOC. It should be noted that the geochemical data used for this well are mean values based on data from neighbouring wells and outcrops.

#### 4.5.2. Simulation results

**4.5.2.1. Burial history.** In the western area (well W11), the sedimentation rate recorded during the Upper Cretaceous–Eocene period is 30 m/Ma (Fig. 13b). However, during the Miocene this parameter reached 80 m/Ma which is related to the transtensional evolution of the basin (Fig. 13b).

In the eastern part of the study area, the Neogene series of the Chelif Basin were deposited on top of the Oligocene and Cretaceous Tellian allochthon (Figs. 2 and 3). In the Tellian allochthonous units underlying the post-nappes Neogene series around the basin borders, the Late Oligocene and Burdigalian series are still characterized by deep water turbidites and only minor erosion has occurred in this formerly basinal domain until the onset of tectonic uplift and basin inversion.

During the development of the Middle Miocene syn-compressional piggyback basin (Langhian–Serravallian), the sedimentation rate was very high with 1000 m/Ma resulting in maximum subsidence particularly in the eastern part of the Chelif Basin (Fig. 14a). During the subsequent transtensional opening of the thrust-top pull-apart basin (Tortonian–Messinian), the sedimentation averaged only 100 m/Ma (Fig. 14a). Therefore, the Upper Miocene subsidence represents only 10% of the Middle Miocene subsidence. Because of renewed transtensional foreland inversion in post-Miocene times, the sedimentation rate was less than 100 m/Ma (Fig. 14a) in the relict depocenters when most of the basin was affected by inversion-related uplift and erosion.

**4.5.2.2. Hydrocarbon generation and expulsion histories.** 1D thermal modelling has been conducted along well W5 in the El-Biod area and along well W11 farther west (Fig. 1b). In the western area (Tahamda), W11 shows that only Upper Cretaceous shales reached the oil generation window 12 Ma ago (Fig. 13a). Oil expulsion was reached since 8 Ma (Fig. 13b) with a maximum expelled oil of 0.8 mg HC/g dry rock (Fig. 13c). However, the Messinian organic rich formations that constitute the second source rock do not reach the oil generation state (Fig. 13b). All Messinian source rocks were modelled using standard Type II kinetics because no Type II-S kinetics were available to model correctly the gypsum marl layer.

In the W5 well, only Middle Miocene organic-rich layers reached the oil generation window and expulsion phase. Oil generation from these layers occurred between 12 and 10 Ma at 4000–4300 m burial depth whilst gas was generated between 6 and 1.5 Ma corresponding to a burial of 4300–5100 m (Fig. 14a). The onset of oil and associated gas expulsion occurred during Tortonian and Messinian times (8–5 Ma). The condensate and associated gas expulsion happened during the Quaternary (Fig. 14b).

The thermal calibration of the present day heat flow model is established using the corrected bottom-hole temperatures (BHT) in the well, while all maturity values are based on Tmax and converted to vitrinite reflectance equivalence (eg. Espitalié, 1986) (Fig. 14c).

The formation of structural traps is related to the Quaternary inversion thus post-dating the Messinian episode of maximum oil expulsion. Nevertheless, a certain amount of hydrocarbons is expelled (Figs. 13c and 14b) after this period. In the W14 well, the Messinian source rock did not reach the hydrocarbon generation window because of an insufficient burial depth (<1000 m, Fig. 13b). However, the gypsum marls of the same formation could have generated commercial amounts of oil at lower temperatures

(<60 °C) in deeper areas. A kinetic model of this organic matter would be required in order to confirm such a scenario.

The Upper Cretaceous series are considered as the main source rock accounting for the oil occurrence in the Upper Miocene reservoir in Tliouanet. They are probably also the source of the gas and oil shows documented elsewhere in the Chelif Basin (Fig. 1b). The Middle Miocene series displays some HC potential in the El-Biod area where the Miocene reservoirs might have been sourced from as indicated by hydrocarbon shows (Fig. 1b).

## 5. Discussion

### 5.1. Thermal evolution of the defined source rocks

In addition to an overall high thermal regime, deep burial might have occurred over the entire basin even near its present borders. Despite the uncertainty of Tmax data in most of the Miocene samples, the low residual potential of a number of samples indicates a high thermal maturity of the organically rich strata caused by significant burial under a thick sedimentary cover in the deep basin.

The very high maturity recorded in the Burdigalian samples (Tmax = 574 °C) and high transformation ratios of the organic-rich Messinian strata (TR = 50–80%) from outcrops require a paleo-burial of at least 1500 to over 2500 m in the currently exhumed areas if we apply the regional geothermal gradients varying from 30 to 45 °C/km throughout the Neogene.

Both at the northern and southern borders, the thermal maturity of Upper Cretaceous samples measured by Tmax varies laterally from an immature state to the onset of oil generation. Although spatial heat flow fluctuation could have occurred, the regional thermal maturity depends mainly on subsidence variations in response to local tectonic activity. This created either burial or a sedimentary hiatus during pre-kinematic and syn-kinematic periods. Apart from Late Cretaceous to Eocene inversion episodes affecting the Atlas foreland and the Early Miocene thin-skinned tectonics operating in the Tell (Roure et al., 2012), the Quaternary inversion phase is most critical for the petroleum systems since thick Upper Miocene and Pliocene series were eroded over a large area in the Chelif basin. Up to 1000 m of Mio-Pliocene series have been eroded as estimated from geometrical extrapolation and 1D thermal modelling in the deeper part of the basin (Fig. 14a).

Using outcrop-based geometrical extrapolations of Late Cretaceous and Paleogene missing sections (Polvéche, 1960) and applying the previously defined heat flow model (Fig. 13a), Upper Cretaceous source rocks in the Dahra and Ouarsenis Mountains near the Tliouanet field reached their present day maturity already at Eocene times. These areas do not record an important Neogene burial since the Telliian inversion (Upper Eocene).

### 5.2. Oil to source rock correlation

In the Ain Zeft area near the northern border of the Chelif Basin, the chemical characteristics of most of the oil and rock extracts reveal that their source rock was deposited in a hypersaline and confined environment. This is consistent with the overall lithofacies description. In addition, the HI of 440 and 566 mg HC/g TOC recorded in the Messinian samples clearly indicates a Type II kerogen. Furthermore, the rapid decrease of the residual potential in the shale samples of the same well or outcrop site (Table 1) is an indication of an early hydrocarbon generation at low Tmax (<430 °C) or temperature (<60 °C). Moreover, there is a good correlation between the basal Tortonian oil and Messinian rock extracts in terms of n-alkane distribution (high proportion of heavy compounds) and low maturity of the samples. The high sulphur

content (>2%) and low oil density (26° API) indicate a sulphur-rich and less mature original organic matter as is actually found in the Messinian source rock. The oil samples of the Ain Zeft field were most likely generated by the Messinian shale.

The results of the gas chromatography show that rock extracts of Upper Cretaceous source rocks and oils from the Tliouanet field originated from a Type II marine kerogen and that they are very mature. Moreover, their n-alkane distributions are very similar. The Tmax and TR values indicate that the maturity of the Upper Cretaceous series varies regionally from onset of oil generation to gas window on the southern border of the basin (Fig. 7 and Table 1). The organic matter is also defined as Type II according to Rock–Eval pyrolysis measurements. Furthermore, because of the weak HC potential of the Middle Miocene and Oligocene marls outside the Hellil area and the nature and lower maturity of the Upper Miocene organic matter, the oils of the Tliouanet field were most likely generated and migrated from the Upper Cretaceous source rocks. However, this chemical correlation should be completed by GC–MS biomarker analysis and isotopic data.

According to their geochemical signature, the Tliouanet oils produced from Tortonian reservoirs are quite similar to the oils of the Oued Gueterini field farther east in the Hodna Basin (Fig. 1a). They have strong affinities to extracts from Upper Cretaceous source rocks. These oils were probably generated from a deeper structural unit followed by dismigration from the subthrust parautochthonous units or underthrust foreland. This interpretation is favoured by the geometry of the Chelif Basin and the location of its main border fault (Fig. 3). This is analogous to Jurassic-sourced oils found in the Neogene reservoirs of the Vienna Basin in Austria (Seifert, 1996) which were actually generated in the lower plate thus accounting for subsequent vertical migration across the sole thrust.

Based on geochemical characteristics, the encountered oil shows from the Oligocene and Miocene formation are indicative of deep source rocks belonging either to Upper Cretaceous or to Oligocene organic carbon rich strata.

### 5.3. Petroleum system analysis

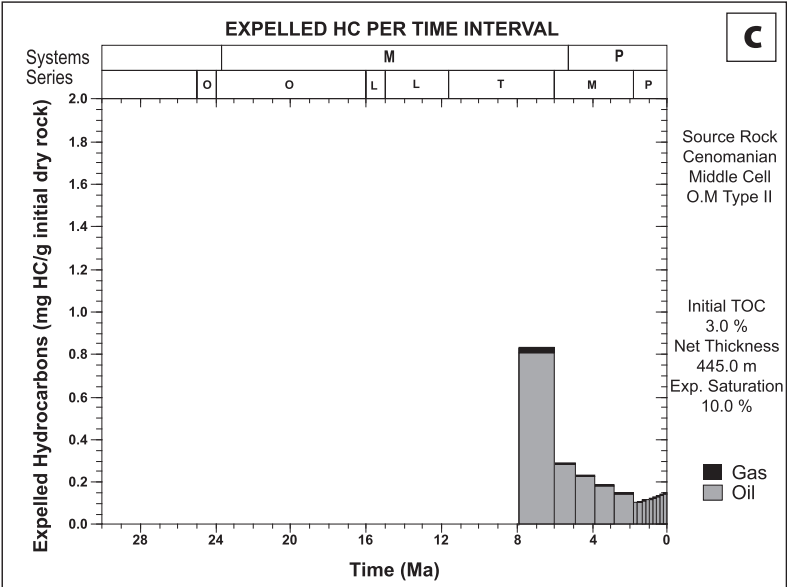
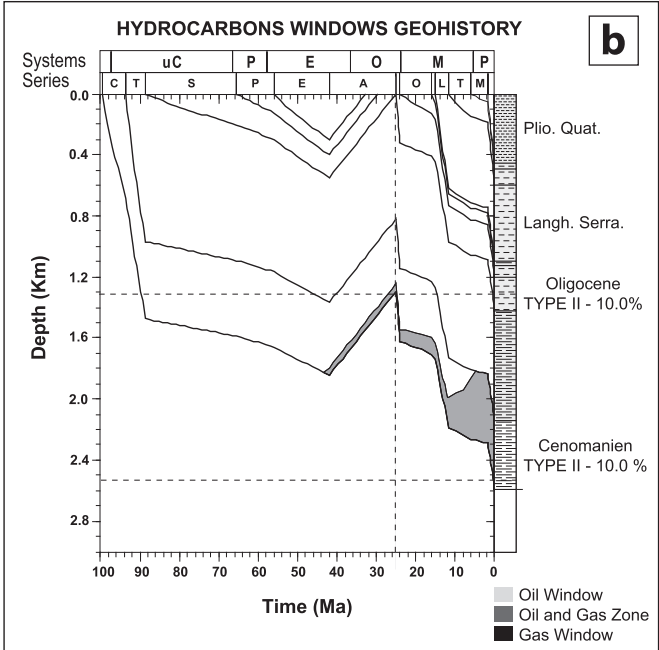
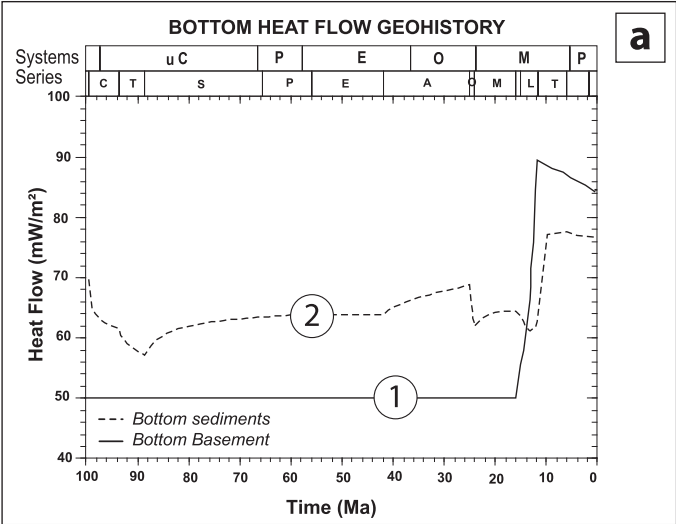
#### 5.3.1. Petroleum system elements

The presence of hydrocarbons in the Chelif Basin demonstrates that geological elements are favourable for the existence of an efficient petroleum system (Fig. 2).

The Tortonian sandstone reservoir presents good characteristics. It is oil bearing in the Tliouanet field while the Middle Miocene reservoirs record oil and gas shows in a large number of wells (Fig. 1b). Despite their limited extension, these reservoirs are well defined in areas such as Ain Zeft and El-Biod (Figs. 5 and 6). They have been studied by Zhang et al. (2009) and Zhang and Jiang (2011) and are generally derived from turbiditic systems (Zhang and Jiang, 2011) whose sandstone bodies are however difficult to predict.

The Eocene compression and thrusting during Lower to Middle Miocene times might have created structural traps in the allochthonous substratum of the Neogene basin. Due to the lateral change of facies (Fig. 2), stratigraphic traps may also exist in the basin and particularly near the basin borders either in the Upper Miocene or in the Middle Miocene series.

Although early anticlines might have already developed in the Telliian allochthon during the Langhian episode of thin-skinned tectonic movements and thrusting especially near the basin borders, the main structural traps formed during the Pliocene episode of transpression resulting in NNW-SSE structural trends (Philip and Thomas, 1977; Philip and Meghraoui, 1983). NE–SW trending (en-echelon folds) and fault-related folds were still active during the





Quaternary (Philip and Meghraoui, 1983; Meghraoui et al., 1986; Meghraoui and Pondrelli, 2012; Derder et al., 2013).

Recent tectonics created structural traps such as the Sedra anticline in the eastern part of the basin. This can be shown on a geological section by the folding of the Pliocene and the erosion of the Quaternary and parts of the Pliocene (Fig. 16).

The oil accumulation in the Tliouanet and Ain Zeft fields and the recorded hydrocarbon shows in Upper Miocene reservoirs indicate a recent charge derived from dismigration from deeper accumulations through faults and also probably by light oil and gas diffusion. In contrast to Miocene reservoirs which are generally overlain by good seals (thick marls and gypsiferous marls), Pliocene reservoirs carry a high risk in terms of seal capacity and hydrocarbon preservation even in the presence of shales in their seal.

### 5.3.2. Potential petroleum systems

**5.3.2.1. Upper Cretaceous (source rocks)/Miocene reservoirs.** In the Tellian allochthon, the Upper Cretaceous (Cenomanian to Campanian) source rocks subcrop below the southern Tliouanet and northern Ain Zeft fields. During basin extension in Tortonian–Messinian times, the Neogene series rest almost directly on the sole thrust of the Tellian allochthon in the central part of the basin. Here, coeval Upper Cretaceous source rocks are more likely to be found at depths appropriate for HC generation in the underthrust foreland and parautochthonous subthrust prospects.

Regionally, the hydrocarbon potential depends on the existence of both reservoirs and kitchen zones. In spite of the presence of a thick Miocene sandstone reservoir unit (200 m) in the Djebel Djira area which belongs to Zone A in the western part of the Chelif basin (Fig. 15), there is no petroleum perspective because of the absence of kitchen zones.

In contrast, zone B is most prospective because of the presence of Tortonian/Messinian reservoirs (TSR and MSR) as well as Upper Cretaceous and Upper Miocene source rocks (Fig. 15). However, as far as exploration results are concerned, wells are mainly dry with only hydrocarbon shows except for the Tliouanet oil field. The principal negative petroleum systems aspects in the Neogene sedimentary infill of the Chelif basin are the fact that reservoirs are missing in a large number of wells and that timing of hydrocarbon migration precedes trap formation. In the Akboub and Hellil areas, the presence of light oil indicates a higher maturity than the rock extracts of the nearby source intervals which require the occurrence of a deeper kitchen and long range lateral and vertical migration. This most likely occurred from the underthrust units towards the Neogene pull-apart either from the deepest parts of the pull-apart basin or from the lower plate using the main border faults of the basin to.

The Zone C consists of two different sub-zones in terms of prospectivity and geology (Fig. 15). The eastern sub-zone is the deepest part of the basin characterized by high sedimentation rates varying from 100 to 1000 m/Ma during the Miocene. Such high sedimentation rates may have caused dilution of the organic matter. Moreover, the geochemical parameters and optical analysis indicate insufficient preservation and alteration of the organic matter in most samples. Furthermore, oil and gas shows recorded from Middle Miocene sands in the W5 well and the small oil accumulation tested from the basal Tortonian reservoir of Sedra (well W18) are either an indication of the generation from deep source rocks such as the Upper Cretaceous or of a re-migration from reservoirs belonging to the substratum (para-autochthonous and

allochthonous sediments) near the basin borders (Fig. 3). Such subthrust prospects would clearly constitute the most attractive targets for oil exploration but they have never been tested beneath the southern part of the Chelif Basin. Analogues for this play are the Monte Alpi and Tempa Rosa play-types of the Southern Apennines (Casero et al., 1991). Despite the presence of reservoirs and source rocks, the most critical element remains the relative timing of trap formation and hydrocarbon charge. This is the case for Pliocene and Quaternary structures such as the Sedra structure where only small oil volumes were produced during tests of the Tortonian reservoir at 1122 m depth (Fig. 16).

The northern part of zone C which includes the Ain Zeft oil field and neighbouring areas is more prospective than the southern part. In addition to the sulphur-rich oils which are originating mainly from Messinian gypsiferous dark-grey marls, light oil (unpublished internal work by Sonatrach) is also present in the Upper Miocene reservoirs and might originate from either Upper Cretaceous source rocks or from organic carbon rich Oligocene black shale layers.

The basin modelling results show that both types of source rock (Upper Cretaceous and Middle Miocene) expelled large amounts of oil during the Tortonian. In contrast, during the Pliocene mainly gas has been expelled into the Upper Miocene reservoirs, particularly from Upper Cretaceous source rock in the eastern area due to its deeper burial.

**5.3.2.2. Messinian source rocks/Upper Miocene reservoirs.** The Messinian source rocks extend along the central part of the basin in the Dahra Mountains and in the Ain Zeft area (Table 1). To be effective, this petroleum system would require:

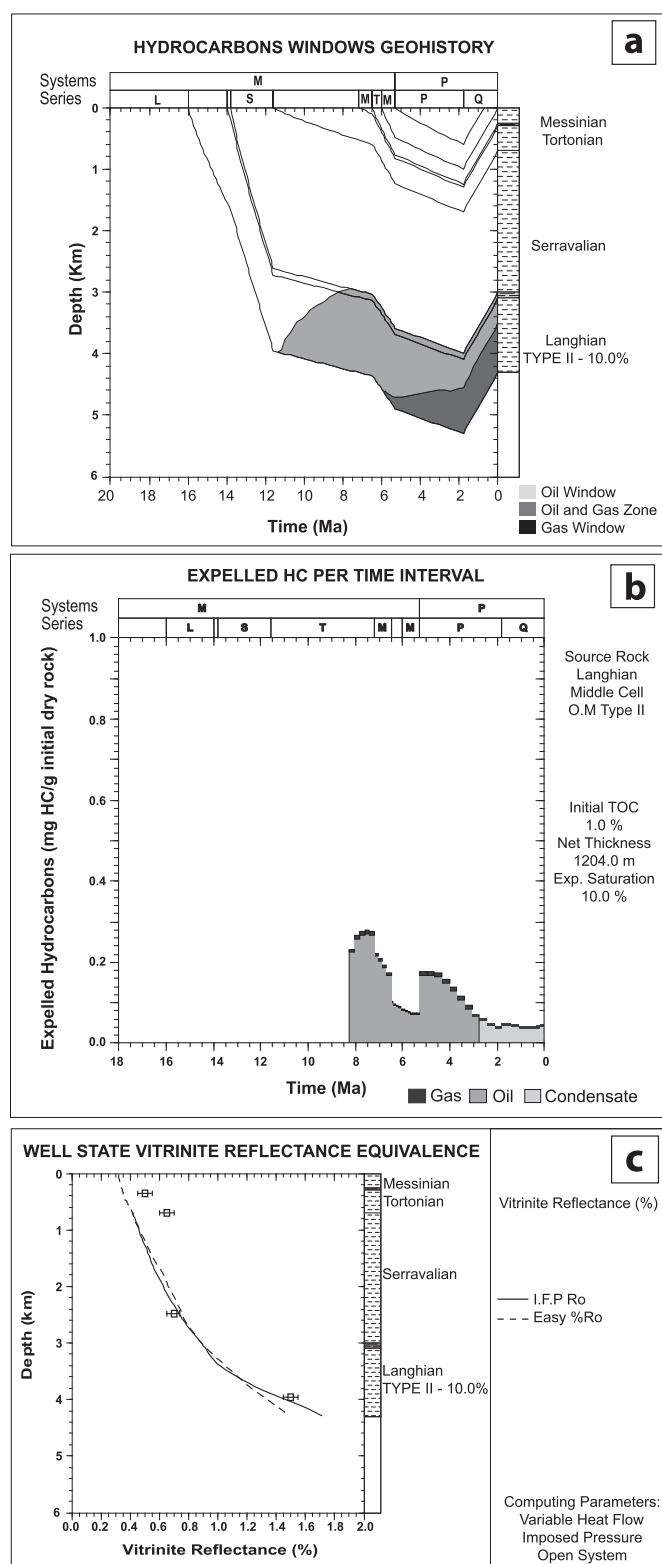
(1) upward migration to Tortonian sandstones and the presence of a Pliocene structure such as Ain Zeft (W3); (2) the presence of a stratigraphic trap which could be formed by an imbrication between the organic-rich layers of the Tripoli formation, gypsiferous black marls and Messinian algal limestones; (3) the presence of a siliciclastic reservoir within the Messinian strata itself and relatively old (at least Pliocene) structures. The third case is verified in the southern Ain Zeft area by the well W17 which discovered a small oil accumulation in Messinian sandstone reservoirs. This oil had been analysed by gas chromatography and is interpreted as originating from an organic matter deposited in a hypersaline environment with a sulphur content of 2.78% (Ten Haven, 1992).

The thickness of the Pliocene to Lower Quaternary sediments is critical for reaching the required temperature of hydrocarbon generation (>60 °C, eg. Peters and Cassa, 1994) and for expelling sufficient quantities of hydrocarbons from Messinian source rocks. This threshold temperature corresponds to 1500 m burial when considering a normal geothermal gradient. Despite a thick Pliocene series (500 à 1000 m) (Fig. 2) in the Fornaka and Belkheir areas which could host both reservoirs and seals, it will be a challenge to trap any commercial hydrocarbons in this play because of the absence of potential source rocks. This is particularly true in the Western area (zone A). Elsewhere, the Pliocene series are thinner ranging from 0 to 50 m mainly due to the Quaternary erosion which is clearly insufficient to expect any efficient reservoir-seal system.

## 6. Conclusions

Despite the Tortonian–Messinian extension, Upper Cretaceous series are still well preserved in the allochthon beneath the Chelif Basin. In outcrops, the Upper Cretaceous (Cenomanian to

**Figure 13.** (a) is the heat flow model at (1) the base of the crust and at (2) the base of sediments which is considered as variable regarding the geodynamic and thermal constraints (Well W11) (b) Graph of the burial and hydrocarbon generation histories of the Upper Cretaceous source rock in the Well W11 (Tahamda). (c) Graph of amounts of expelled oil and gas (in mg HC/g dry rock) from the Upper Cretaceous source rock.



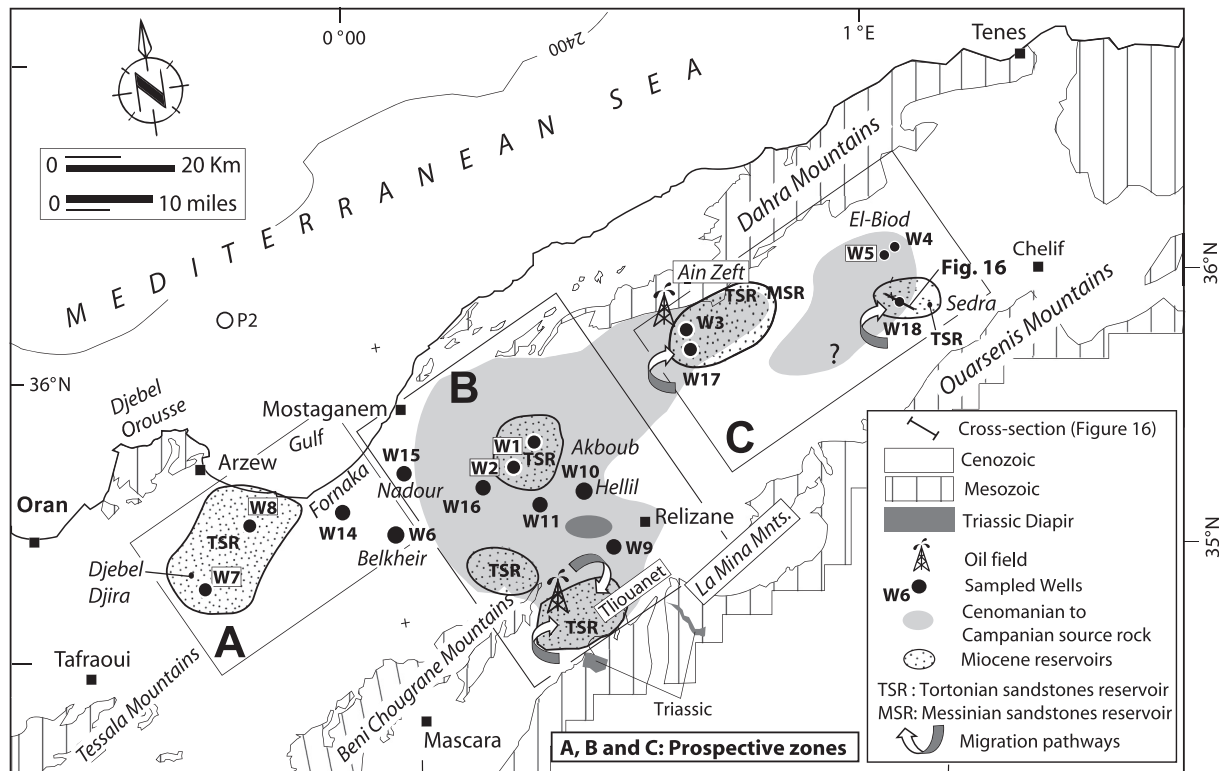
**Figure 14.** (a) Burial and hydrocarbon generation histories from the Middle Miocene rich layers considered as secondary source rock (Well W5). (b) Graph presenting amounts of expelled oil and gas (in mg HC/g dry rock) per time interval, from the Middle Miocene organically rich layers. (c) Graph of vitrinite reflectance equivalence (VReq) versus depth indicating a calibration between the calculated and measured values.

Campanian) source rocks of the Tellian allochthon are frequently made up of discontinuous patches reworked in tectonic melanges along the sole thrust or of shallow erosional remnants between the main Neogene depocenters and the frontal Tellian thrust. The occurrence of oil with a geochemical footprint of Upper Cretaceous source rocks in the Tliouanet field near the main border fault of the Chelif Basin suggests a dismigration from the subthrust foreland or the parautochthonous structures which formed during the Plio-Pleistocene episode of transpression. This makes the subthrust play a potential target. The main exploration risk is the possible erosion of Cretaceous platform carbonate reservoirs and Albian sands of subthrust prospects prior to the development of the Neogene foreland flexure and deposition of deep water seals due to Late Cretaceous to Eocene foreland inversion (Roure et al., 2012).

The Oligocene Numidian series display locally high organic carbon content in Sicily and Tunisia where they are known to account for effective petroleum systems (El Euch et al., 2004; Granath and Casero, 2004). Despite the fact that only hydrocarbon shows have been recorded in Oligocene Numidian sandstones in Northern Algeria (eastern Tellian domain), the Oligocene series of the Tellian allochthon in the vicinity of the Chelif Basin show the same overall characteristics and could still constitute a target for petroleum exploration. In the basin itself, only few samples of black marls from the W9 well show fair organic carbon content and fair residual potential at the onset of oil generation.

Despite a significant thickness of Middle Miocene grey marls (av. 2000 to >4000 m), only thin layers are found to be organic-matter rich with a fair to low generative potential within a limited area. This is due in part to the conditions of preservation and probably also of sample storage since many wells were drilled during the 1950s. Furthermore, the low HC potential may also be due to dilution especially in the deepest part of the basin which likely induces a matrix effect during pyrolysis. In addition, optical analysis and Rock–Eval parameters show that there is an effect of oxidation.

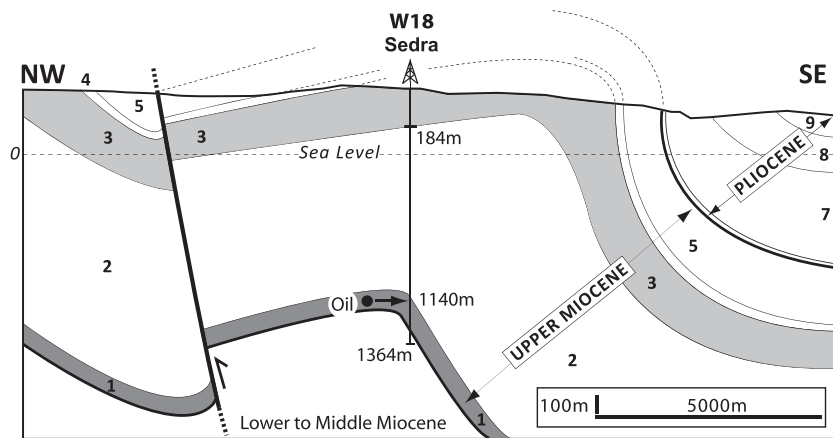
In contrast, the basal grey marls, the Tripoli formation and the gypsiferous dark-grey marls of Messinian age have all good geochemical characteristics. According to their transformation ratios, thermal maturity varies regionally from an immature state near the basin borders (Ain Zeft and northern Ouarsenis Mountains) to oil generation (TR = 80%) in Fornaka to the West. However, the kitchen zones of Messinian source rocks may be very limited in area. Such zones exist in the eastern Akboub area, southern Ain Zeft and in El-Biod where the cumulative thickness of the Messinian and Pliocene series reaches an average of 1500 m. In the eastern area (well W5), the 1D basin modelling suggests that the timing of oil generation from the Middle Miocene organic-carbon rich layers which can be considered as a secondary source occurred mainly during the Upper Miocene, and the timing of gas generation from Pliocene to present day. Oil expulsion began at 8 Ma and lasted until 4 Ma. From 5 Ma to present, mainly condensate and gas expulsion occurred. In the western part of the Chelif Basin, the modelling of the W11 well indicates a timing of oil generation in the Cenomanian source rock from 40 Ma to present. However, oil expulsion began only at 8 Ma because oil saturation in the source rock was not sufficient to trigger expulsion earlier. In any case, the GC/GC–MS analysis confirms the correlation between the Ain Zeft oil in basal Tortonian and Messinian reservoirs (which contains oleanane) and the HC extracts of the Late Messinian gypsum dark-grey marls. The main exploration risk for the Neogene hydrocarbon systems relates to the scarcity of clastic reservoirs in the sedimentary infill of the pull-apart basin that is dominated by fine grained growth strata and where most anticlinal structures are controlled by salt domes. Stratigraphic traps and sandy paleo-channels could occur along the flanks of the structures or in intervening lows but they are very



**Figure 15.** Map showing location of the Upper Cretaceous kitchen zones and the spatial extension of the Miocene reservoirs and zonation in terms of prospectivity of Upper Cretaceous (SR)/Upper Miocene (reservoirs) petroleum system (TSR: Tortonian sandstone reservoir; MSR: Messinian sandstone reservoir; MMR: Middle Miocene reservoir).

difficult to map due to lack of 3D seismic data. Plio-Pleistocene anticlines related to the recent inversion of the basin are likely to post-date the episodes of maximum burial in the Miocene depocenters even if they could host re-migrated oil from older structures or oil escaping vertically from the subthrust units along vertical conduits such as the main border fault of the basin. This is shown by the existence of migrated high mature oil in the Middle Miocene or Oligocene marls of the Chelif basin and by the Tliouanet

oil field where charge can be genetically correlated to Upper Cretaceous source rocks most probably derived from an ancient accumulation in the substratum by remigration. A similar mode of petroleum charge is known to occur in the Vienna Basin in Austria (Seifert, 1996) where the oil generated in Jurassic source rocks from the lower plate has migrated upward across the Alpine nappes before being trapped in Neogene clastic deposits of the thrust-top pull-apart basin (Sauer et al., 1992; Seifert, 1996).



**Upper Miocene:** 1-Sandstones (*Grès de base*); 2-Marls (*Marnes bleues*);  
3- Marls (*Marnes à Tripolis*); 4-Gypsiferous Level; 5- Gypsiferous marles  
**Pliocene:** 6-Sandstones (*Grès de base*); 7-Marls (*Marnes bleues*); 8-Sandstones;  
9-Continental deposits

Tenaille, M. (1942), Relizane (ex: Rabelais), Services des Recherches Minières. Unpublished. Sonatrach well report.

**Figure 16.** Geological section presenting a structure of recent tectonics (Quaternary inversion) and oil accumulation in the Middle Miocene reservoir. This is one of the trap models existing in the Chelif basin.

## Acknowledgements

This work was conducted as part of a Master II research work carried out at USTHB University (Algiers). The authors wish to thank Sonatrach and Alnaft for giving access to the well data. We acknowledge M. Kaced and Dj. Belhai for reviewing an early draft of the manuscript and F. Klingelhoefer for the English corrections. We greatly benefited from discussions with A. Lassal and H. Benali. We thank anonymous reviewers for their positive and constructive review and also the Associate Editor Johannes Wendebourg for the assistance in the final version of the paper.

## References

- Abtout, A., Boukrout, H., Bouyahiaoui, B., Gibert, D., 2014. Gravimetric evidences of active faults and underground structure of the Cheliff seismogenic basin (Algeria). *J. Afr. Earth Sci.* 99, 363–373.
- Aït Hamou, F., 1987. Etude pétrographique et géochimique du volcanisme d'âge Miocène de la région de Hadjout (Ouest Algérois) (Thèse de magister). Université des Sciences et de la Technologie Houari Boumediene, Bab Ez Zouar, Algiers, Algeria, p. 222.
- Anderson, R.V.V., 1936. Geology in the coastal Atlas of Western Algeria. *Geol. Soc. Am. Mem.* 4, 450.
- Barker, C., 1974. Pyrolysis techniques for source-rock evaluation. *Am. Assoc. Pet. Geol. Bull.* 58 (11), 2349–2361.
- Beardmore, G.R., Cull, J.P., 2001. *Crustal Heat Flow: a Guide to Measurement and Modeling*. Cambridge University Press, United Kingdom, p. 519.
- Behar, F., Beaumont, V., De B. Penteako, H.L., 2001. Rock-Eval 6 technology: performances and developments. *Rev. l'Institut Français Pétrole* 56, 111–134.
- Behar, F., Huc, A., Da Silva, M., IFP-EN, Sonatrach Tell-Offshore Team, 2006. Geochemistry of source rocks and oils. In: Roure, F., Addoum, B., et al. (Eds.), *Architecture and Petroleum Appraisal of Northern Algeria*. IFP-EN and Sonatrach Report, N° 59520, Tell-Offshore JIP, vol. 1, pp. 83–90 (unpublished Report).
- Beicip-Franlab, 1995. *Genex Single Well (User Guide)*. Beicip-Franlab, France, p. 464.
- Bellon, H., Brousse, R., 1977. Le magmatisme périméditerranéen occidental: essai de synthèse. *Bull. la Société Géologique Fr.* 7, 469–480.
- Benaouli-Mebarek, N., Frizon de Lamotte, D., Roca, E., Bracène, R., Faure, J.L., Sassi, W., Roure, F., 2006. Post-Cretaceous kinematics of the Atlas and Tell systems in central Algeria: early foreland folding and subduction related deformation. *C. R. Géosci.* 338, 115–125.
- Bordenave, M.L., Durand, B., 1993. Evolution of ideal and concepts in geochemistry. In: Bordenave, M.L. (Ed.), *Applied Petroleum Geochemistry*. Editions Technip, Paris, pp. 3–14 (Chapter 1).
- Boudiaf, A., Ritz, J.F., Philip, H., 1998. Drainage diversions as evidence of propagating active faults: example of the El Asnam and Thénia Faults, Algeria. *Terra Nova* 10, 236–244.
- Bracène, R., Frizon de Lamotte, D., 2002. The origin of intraplate deformation in the Atlas system of western and central Algeria: from Jurassic rifting to Cenozoic-Quaternary inversion. *Tectonophysics* 357, 207–226.
- Brooks, J.D., Gould, K., Smith, J.W., 1969. Isoprenoid hydrocarbons in coal and petroleum. *Nature* 222, 257–259.
- Carminati, E., Wortel, M.J.R., Meijer, P. Th., Sabadini, R., 1998. The two-stage opening of the western-central Mediterranean basins: a forward modelling test to a new evolutionary model. *Earth Planet. Sci. Lett.* 160, 667–679.
- Chaouche, A., 1992. *Genèse et mise en place des hydrocarbures dans le bassin de l'Erg Oriental (Sahara Algérien)* (Thèse de Doctorat). Université Michel de Montaigne, Bordeaux 3, France, p. 347.
- Casero, P., Roure, F., Vially, R., 1991. Tectonic framework and petroleum potential of the southern Apennines. In: Spencer, A.M. (Ed.), *Generation, Accumulation and Production of Europe's Hydrocarbons*. Oxford University Press, U. K., pp. 381–387.
- Correia, M., 1967. Relations possible entre l'état de conservation des éléments figurés de la matière organique et l'existence de gisements d'hydrocarbures. *Rev. l'Institut Français Pétrole* 22, 1285–1306.
- Derder, M.E.M., Henry, B., Maouche, S., Bayou, B., Amenna, M., Besse, J., Bessedik, M., Belhai, D., Ayache, M., 2013. Transpressive tectonics along a major E–W crustal structure on the Algerian continental margin: blocks rotations revealed by a paleomagnetic analysis. *Tectonophysics* 193, 183–192.
- Di Primio, R., Horsfield, B., 1996. Predicting the generation of heavy oils in Carbonate/Evaporitic environments using pyrolysis methods. *Org. Geochem.* 24 (10–11), 999–1016.
- Deveaux, J., 1965. Pour une mise à jour des connaissances géologiques et pétrolières dans les bassins sublittoraux de l'Algérie Nord occidentale (unpublished report of SN.REPAL, Algeria).
- Domzig, A., Yelles, K., Le Roy, C., Deverchère, J., Bouillin, J.P., Bracène, R., Mercier de Lépinay, B., Le Roy, P., Calais, E., Kherroubi, A., Gaullier, V., Savoye, B., Pauc, H., 2006. Searching for the Africa-Eurasia Miocene boundary offshore western Algeria (MARADJA'03cruise). *C. R. Géosci.* 338, 80–91.
- Didyk, B.M., Simoneit, B.R.T., Brassell, S.C., Eglington, G., 1978. Organic geochemical indicators of palaeoenvironmental conditions of sedimentation. *Nature* 272, 216–222.
- Durand-Delga, M., Fontobé, J.M., Vila, J.M., 1980. Le cadre structural de la Méditerranée occidentale. 26th International Geological Congress, Paris, Collection 5, BRGM, France. *Mémoire* 115, 67–85.
- El Euch, H., Saidi, M., Fourati, L., El Makerssi, C., 2004. Northern Tunisia thrust belt: deformation models and hydrocarbon systems. In: Swennen, R., Roure, F., Granath, J.W. (Eds.), *Deformation, Fluid Flow and Reservoir Appraisal in Foreland Fold-and-thrust Belts*, American Association of Petroleum Geologists Memoir, Hedberg Series, vol. 1, pp. 371–390.
- Eglington, T.L., Sinninghe-Damasté, J.S., Kohnen, M.E.L., de Leeuw, J.W., Larter, S.R., Patience, R.L., 1989. Analysis of maturity-related changes in the organic sulfur composition of kerogens by flash pyrolysis-gas chromatography, geochemistry of sulfur in fossil fluids. In: Orr, W.L., White, C.M. (Eds.), *Geochemistry of Sulfur in Fossil Fuels*, American Chemical Society, ACS Symposium Series, 429, pp. 529–565.
- Espitalié, J., Laporte, J.L., Madec, M., Marquis, F., Leplat, P., Paulet, J., Boutefeu, A., 1977. Méthode rapide de caractérisation des roches mères, de leur potentiel pétrolier et de leur degré d'évolution. *Rev. l'Institut Français Pétrole* 32, 23–42.
- Espitalié, J., Deroo, G., Marquis, F., 1985. La pyrolyse Rock-Eval et ses applications. *Rev. l'Institut Français Pétrole* 40, 563–578.
- Espitalié, J., 1986. Use of Tmax as a maturation index for different types of organic matter. Comparison with vitrinite reflectance. In: Burrus, J. (Ed.), *Thermal Modelling in Sedimentary Basins*. Technip, Paris, pp. 475–496.
- Espitalié, J., Deroo, G., Marquis, F., 1986. Rock-Eval pyrolysis and its applications. *Rev. l'Institut Français Pétrole* 41, 73–89.
- Fenet, B., 1975. Recherches sur l'Alpinisation de la bordure septentrionale du Bouclier Africain, à partir de l'étude d'un élément de l'Orogenèse nord-maghrébin: Les monts de Tessala du Djebel Tessala et les massifs du littoral Oranaïs (Doctorat d'Etat). Institut polytechnique Méditerranéen, Université de Nice, France, p. 301.
- Fingas, M., 2010. Oil spill science and technology. In: Fingas, M. (Ed.), *Gulf Professional Publishing*. Elsevier, Inc., p. 1192.
- Frizon de Lamotte, D., Michard, A., Saddiqui, O., 2006. Some recent developments on the Maghreb geodynamics. *C. R. Géosci.* 338, 1–10.
- Granath, J.W., Casero, P., 2004. Tectonic setting of the petroleum systems of Sicily. In: Swennen, R., Roure, F., Granath, J.W. (Eds.), *Deformation, Fluid Flow and Reservoir Appraisal in Foreland Fold-and-thrust Belts*. American Association of Petroleum Geologists Memoir, Hedberg Series, vol. 1, pp. 391–411.
- Guemache, M.A., 2010. *Evolution géodynamique des bassins sismogènes de l'Algérie (Algérie): approche pluridisciplinaires (méthodes géologiques et géophysiques)* (Thèse de Doctorat). Université des Sciences et de la Technologie Houari Boumediene, Bab Ez Zouar, Algiers, Algeria, p. 294.
- Guido, A., Jacob, J., Gautret, P., Aggoun-Déferge, F., Mastandrea, M., Russo, F., 2007. Molecular fossils and other organic markers as palaeoenvironmental indicators of the Messinian Calcare di Base Formation: normal versus stressed marine deposition (Rossano Basin, northern Calabria, Italy). *Palaeogeogr. Palaeoclimatol. Palaeoecol.* 255, 265–283.
- Hardie, L.A., Eugster, H.P., 1971. The depositional environment of marine evaporites: a case of shallow clastic accumulations. *Sedimentology* 16, 187–220.
- Hsü, K.J., 1971. Origin of the Alps and western mediterranean. *Nature* 233, 44–48.
- Hunt, J.M., 1979. *Petroleum Geochemistry and Geology*. W. H. Freeman and Co Editions, San Francisco, p. 617.
- Jones, R.W., Edison, T.A., 1978. Microscopic observations of kerogen related to geochemical parameters with emphasis on thermal metamorphism of kerogen and clay minerals. In: SEPM Pacific Section, Los Angeles, October, 1–12.
- Kheidri, H.L., Zazoun, R.S., Sabaou, N., 2007. Neogene tectonic history of the sub-bibanic and M'Sila basins, Northern Algeria: implications for hydrocarbon potential. *J. Pet. Geol.* 30 (2), 159–174.
- Kieken, M., 1974. Etude géologique du Hodna, du Titteri et de la partie occidentale des Biban. Publication du Service de la Carte géologique de l'Algérie, p. 498, 46, Tome I et II.
- Lehne, E., Dieckmann, V., 2007. Bulk kinetic parameters and structural moieties of asphaltenes and kerogens from a sulfur-rich source rock sequence and related petroleum systems. *Org. Geochem.* 38 (10), 1657–1679.
- Lingrey, S., 2007. Cenozoic deformation of Trinidad: foldbelt restoration in a region of significant strike-slip. In: Lacombe, O., Roure, F., Lavé, J., Vergés, J. (Eds.), *Thrust Belts and Foreland Basins*, Frontiers in Geosciences. Springer, pp. 163–178.
- Louni-Hacini, A., Bellon, H., Maury, R.C., Megartsi, M., Coulon, C., Semroud, B., Cotten, J., Coutelle, A., 1995. Datation 40K–40Ar de la transition du volcanisme calco-alcalin au volcanisme alcalin en Oranie au Miocène supérieur, 321. *Comptes Rendus Académie des Sciences, Paris*, pp. 975–982.
- Lumbach, G.W.M., Deam, R.J., Leather, J., Hale, J.G., Fedynsky, V.V., Karus, E.V., Polshkov, M.K., 1975. On the origin of petroleum, world petroleum energy model, geophysical and geochemical surface surveys for detection of oil & gas pools. In: Preprint of the Proceedings of the 9th World Petroleum Congress Special Papers 1 & 11, Review #2.
- Lüning, S., Kolonic, S., Belhadj, E.M., Belhadj, Z., Cota, L., Baric, G., Wagner, T., 2004. Integrated depositional model for the Cenomanian-Turonian organic-rich strata in North Africa. *Earth-Sci. Rev.* 64, 51–117.
- Mansour, B., Moissette, P., Noël, D., Rouchy, J.M., 1994. L'enregistrement par les associations de diatomées des environnements Messiniens: l'exemple de la coupe de Sig. *Geobios* 28 (3), 261–279.



- Mansour, B., Bessedik, M., Saint Martin, J.P., Belkebir, L., 2008. Signification paléocéologique des assemblages de diatomées du Messinien du Dahra sud-occidental (basin de Chelif, Algérie nord-occidentale). *Geodiversitas* 30, 117–139.
- Marillier, F., Mueller, S., 1982. The western Mediterranean region as an upper-mantle transition zone between two lithospheric plates. *Tectonophysics* 118 (1–2), 113–130.
- Masrouhi, A., Koyi, L.H., 2012. Submarine “salt glacier” kinematics of Northern Tunisia, a case of Triassic salt mobility in North African Cretaceous passive margin. In: Alsop, G.I., Archer, S.G., Hartley, A., Grant, N.T., Hodgkinson, R. (Eds.), *Salt Tectonics, Sediments and Prospectivity*, Special Publications, vol. 363. Geological Society, London, pp. 579–593.
- Mattauer, M., 1958. Etude Géologique de l'Ouarsenis Orientale, Algérie. Publication du Service de la Carte Géologique de l'Algérie, p. 543. Bulletin N° 17, Nouvelle Série.
- Maury, R.G., Fourcade, S., Coulon, C., El Azzouzi, M., Bellon, H., Coutelle, A., Ouabadi, A., Semroud, B., Megartsi, M., Cotton, J., Bellanteur, O., Lounil-Hacini, A., Piqué, A., Capdevila, R., Hernandez, J., Rehault, J.P., 2000. Post-collisional Neogene Magmatism of the Mediterranean Maghreb Margin: a Consequence of Slab Breakoff, vol. 331. *Comptes Rendus de l'Académie des Sciences*, Paris, pp. 159–173.
- Meghraoui, M., 1982. Etude néotectonique de la région nord-est d'El Asnam, relation avec le séisme du 10/10/1980 (Doctorat 3° Cycle). Université de Paris VI, France, p. 190.
- Meghraoui, M., Cisternas, A., Philip, H., 1986. Seismotectonics of the lower Chelif Basin: structural background of the El -Asnam (Algeria) earthquake. *Tectonics* 5 (6), 809–836.
- Meghraoui, M., 1988. Géologie des zones sismiques du nord de l'Algérie: Paléosismologie, tectonique active et synthèse sismotectonique (Thèse de Doctorat). Université de Paris XI, France, p. 356.
- Meghraoui, M., Doumaz, F., 1996. Earthquake-induced flooding and paleoseismicity of the El Asnam (Algeria) fault-related fold. *J. Geophys. Res.* 101, 17617–17644.
- Meghraoui, M., Morel, J.L., Andrieux, J., Dahmani, M., 1996. Tectonique plioquaternaire de la chaîne tello-rifaine et de la mer d'Alboran. Une zone complexe de convergence continent-contin. *Bull. la Société Géologique Fr.* 167 (1), 141–157.
- Meghraoui, M., Pondrelli, S., 2012. Active faulting and transpression tectonics along the plate boundary in North Africa. *Ann. Geophys.* 55, 5. <http://dx.doi.org/10.4401/ag-4970>.
- Neuridin-Trescartes, J., 1992. Le remplissage sédimentaire du bassin néogène du Chélif, modèle de référence de bassins intra-montagneux (Doctorat d'Etat). Académie de Bordeaux, France, p. 605.
- Neuridin-Trescartes, J., 1995. Paléogéographie du bassin de Chélif (Algérie) au Miocène. Causes et Conséquences. *Géologie Méditerranéenne* XXII (2), 61–71.
- Olivier, Ph., 1984. Evolution de la limite entre Zones internes et Zones externes dans l'Arc de Gibraltar (Maroc-Espagne) (Thèse de Doctorat). Université Paul Sabatier, Toulouse, France, p. 229.
- Orr, W.L., 1986. Kerogen/asphaltene/sulfur relationships in sulfur-rich Monterey oils. *Adv. Org. Geochem.* 10, 499–516.
- Perrodon, A., 1957 (PhD thesis). Etude géologique des bassins néogènes sublittoraux de l'Algérie occidentale, vol. 12. Nancy University, Publication du Service de la Carte Géologique de l'Algérie, p. 328.
- Polvéche, J., 1960. Contribution à l'étude géologique de l'Ouarsenis Oranais. Service de la Carte Géologique de l'Algérie, p. 577. Bulletin n° 24.
- Peters, K.E., Cassa, M.R., 1994. Applied source rock geochemistry. In: Magoon, L.B., Dow, W.G. (Eds.), *Petroleum System – from Source to Trap*, Memoir, vol. 60. American Association of Petroleum Geologists, pp. 93–117.
- Peters, K.E., Walters, C.C., Moldowan, J.M., 2005. *The Biomarker Guide*. Cambridge University Press, Cambridge, U. K., p. 1155.
- Philip, H., Thomas, G., 1977. Détermination de la direction de raccourcissement de la phase de compression quaternaire en Oranie (Algérie). *Revue de Géogr. Physique de Géologie Dynamique* 19 (4), 315–324.
- Philip, H., Meghraoui, M., 1983. Structural analysis and interpretation of the surface deformation of the El Asnam earthquake of October 10, 1983, geodetic determination of vertical and horizontal movements. *Bull. Seismol. Soc. Am.* 72, 2227–2224.
- Riahi, S., Khalfa, K.B., Soussi, M., Ismail-Latrache, K.B., 2007. The Numidian Flysch complex of Onshore Tunisia (Southern Kroumirie Range)-facies analysis and stratigraphic review. In: 3rd North African/Mediterranean-Petroleum and Geosciences Conference and Exhibition, Tripoli, Libya, 26–28, February 2007.
- Rouchy, J.M., 1981. La genèse des évaporites messiniennes de Méditerranée (Thèse Doctorat d'Etat). Université Paris VI, France, p. 295.
- Rouchy, J.M., 1982. La genèse des évaporites messiniennes de Méditerranée. In: *Mémoires du Muséum National de l'Histoire Naturelle*, L, p. 267.
- Rouchy, J.M., Caruso, A., Pierre, C., Blanc-Valleron, M.M., Bassetti, M.A., 2007. The end of the Messinian salinity crisis : evidences from the Chelif basin (Algeria). *Paleogeogr. Paleoclimatol. Paleocol.* 254, 386–417.
- Roure, F., 2008. Foreland and hinterland basins: what controls their evolution? *Swiss J. Geosci.* 101, 1–24.
- Roure, F., Casero, P., Addoum, B., 2012. Alpine inversion of the North African Margin, and delamination of its continental crust. *Tectonics* 31, TC3006. <http://dx.doi.org/10.1029/2011TC002989>.
- Ryan, W.B.F., 2011. Geodynamic responses to a two-step model of the Messinian salinity crisis. *Bull. la Soc. Géologique Fr.* 2, 73–78.
- Sauer, R., Seifert, P., Wessely, G., 1992. Guide Book to Excursion in the Vienna Basin and the Adjacent Alpine-Carpathian Thrust Belt in Austria. *Mitteilungen der Österreichischen Geologischen Gesellschaft*, p. 85.
- Schaeffer, P., Reiss, C., Albrecht, P., 1995. Geochemical study of macromolecular organic matter from sulfur-rich sediments of evaporitic origin (messinian of Sicily) by Chemical degradations. *Org. Geochem.* 23, 567–581.
- Seifert, P., 1996. Sedimentary-tectonic development and Austrian hydrocarbon potential of the Vienna Basin. In: Wessely, G., Liebl, W. (Eds.), *Oil and Gas in Alpidic Thrustbelts and Basins of Central and Eastern Europe*, vol. 5. European Association of Geological Engineering Special Publication, pp. 331–342.
- Spakman, W., Wortel, R., 2004. A tomographic view on Western Mediterranean geodynamics. In: Cavazza, W., Roure, F., Spakman, W., Ziegler, P. (Eds.), *The TRANSMED Atlas: the Mediterranean Region from Crust to Mantle*. Springer, New-York, pp. 31–52.
- Staplin, F.L., 1969. Sedimentary organic matter, organic metamorphism, and oil and gas occurrence. *Can. Pet. Geol. Bull.* 17, 47–66.
- Stow, D.A.V., Johansson, M., Braakenburg, N.E., Faugères, J.C., 1999. Deep-water massive sands: facies, processes and channel geometry in the Numidian Flysch, Sicily. *Sediment. Geol.* 127 (1–2), 119–123.
- Takherist, D., Lesquer, A., 1989. Mise en évidence d'importantes variations régionales de flux de chaleur en Algérie. *Can. J. Earth Sci.* 26, 615–626.
- Ten Haven, H.L., 1992. Geochemistry of Oils and Potential Source Rocks, from North Algeria. N° RL 4925, Total-Algeria (unpublished report).
- Thomas, G., 1985. Géodynamique d'un bassin intramontagneux, le bassin de Chélif occidental (Algérie), durant le Mio-Plio-Quaternaire (Thèse d'Etat). Université de Pau et des pays de l'Adour, France, p. 594.
- Thomas, M.F.H., Bodin, S., Redfern, J., Irving, D.H.B., 2010. A constrained African craton source for the Cenozoic Numidian Flysch: implications for the palaeogeography of the western Mediterranean basin. *Earth-Sci. Rev.* 101, 1–23.
- Tissot, B.P., Welte, D.H., 1984. *Petroleum Formation and Occurrence*. Springer, Berlin, p. 699.
- Ungerer, P., Burrus, J., Doligez, B., Chenet, P.-Y., Bessis, F., 1990. Basin evaluation by integrated 2D modeling of heat transfer, fluid flow, hydrocarbon generation and migration. *Am. Assoc. Pet. Geol. Bull.* 74, 309–335.
- Vila, J.M., 1994. Mise au point des données nouvelles sur les terrains triasiques des confins algéro-tunisien: Trias allochtone, “glacier de sel” sous-marins et vrais diapirs. In: Dercourt, J., Tefani, M., Vila, J.M. (Eds.), *Trias 93, Mémoire du Service Géologique de l'Algérie*, vol. 6, pp. 105–152.
- Vila, J.M., Sigal, J., Lahondère, J.C., 1993. Position en fenêtre de la série néritique constantinoise sous la nappe de Djemila: observations nouvelles du Djebel Mazela (massif du Djebel Oum Settas, Algérie du Nord-Est). In: *Comptes Rendus de l'Académie des Sciences. Série II*, vol. 317, pp. 395–401.
- Waples, D.W., Machihara, T., 1991. Biomarkers for Geologists: a practical guide to the application of steranes and triterpanes in petroleum exploration. *Am. Assoc. Pet. Geol.* 9, 91–100.
- Wezel, F.C., 1969. Lineamenti Sedimentologico Del Flysch Numidico Della Sicilia Nord-Orientale. *Mem. Degli Istituti Geol. Mineral. Del L'Universita Padova* 26, 1–32.
- Yelles-Chaouche, A., Boudiaf, A., Djellit, H., Bracène, R., 2006. La tectonique active de la région nord algérienne. *C. R. Géosci.* 338, 126–139.
- Zhang, Y.F., Jiang, Z.X., Wang, Y., Bao, D.D., 2009. Comparative analysis of sequence characteristics among different superimposed stages of the Chelif basin Algeria. *Acta Geol. Sin. – Engl. Ed.* 83 (6), 1041–1051.
- Zhang, Y.F., Jiang, Z.X., 2011. Outcrop characterization of an early Miocene slope fan system, Chelif basin Algeria. *Energy Explor. Exploit.* 29 (5), 633–646.