Petroleum and Coal

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Geological and Geochemical Evaluation of Shale Gas Potential of the Tanezzuft Formation, Ghadames Basin, North Africa

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Received March 11, 2024; Accepted June 11, 2024

Abstract

The Ghadames Basin is a poly-history Palaeozoic basin covering parts of Tunisia, Algeria and Libya. Exploration efforts in the past which targeted conventional hydrocarbon resources have been most successful in the Algerian segment. The aim of this research was to undertake a geological and geochemical assessment of the 'world class Silurian Tanezzuft Formation, model the timing of hydrocarbon generation and expulsion within the basin, all in a bid to evaluate its shale gas potential. Data from forty-nine (49) wells, which consist of total organic carbon (TOC), thermal maturity (Tmax), and kerogen (Hydrogen Index) were utilised for this study. TOC and Thermal maturity maps with cut-offs of 2wt.% and 1.0 $R_{oequvalent}$ which were generated show an increase of organic richness and maturity towards the West/NW. Subsequently integration of maps show favourable shale gas potential in a major 'sweet spot' area in the Western Ghadames Basin, with geological and geochemical characteristics that compare favourably with established similar aged gas shales in the US. Furthermore, 1-D basin models generated from an existing well and a pseudo well within the identified sweet spot area using a linear heat flow model reveal a good potential for thermogenic gas adsorption as well as an upside for shale oil. However, the risk and uncertainties associated with the shale gas development may be heightened due to non-technical issues such as political instability, access to technical support, water supply for fracking operations as well as potential environmental issues such as groundwater contamination with methane and induced seismicity arising from hydraulic fracturing.

Keywords: *Paleozoic Shale; Sweet spot; 1D Basin Modelling; Unconventional gas.*

1. Introduction

Shale gas systems are mud-sized sedimentary units, which in themselves act as source, reservoir, and seal units. They form continuous gas accumulations, unlike conventional plays that require migrating pathways and traps. The fine-grained nature of gas shale reservoirs implies a different method of development/production as distinct from conventional gas reservoirs due to unfavourable petrophysical properties. Consequently, a combination of horizontal drilling and hydraulic fracturing methods are employed for optimum gas extraction [1]. Its low CO_2 emission coupled with its abundant reserves makes it an important energy resource for the Future [2]. The USA has been the most successful in exploiting this critical clean energy resource. In fact, in 2018 shale gas contributed 64% of the total natural gas produced in the US [3]. China, Canada and Argentina have also followed suit, evidenced by commercial volumes produced in recent time [4]. The Russian – Ukraine war which is threatening Europe's energy security makes it fair to predict that shale gas resource in UK,, Poland, North Africa, etc., will play a big role in satisfying the energy needs of western Europe and indeed the whole world in the future, Consequently there is an immediate need to evaluate the potential of shale gas resources in the Ghadames Basin, North Africa. The Ghadames Basin, which was initiated in the Palaeozoic, is a large polycyclic basin, encompassing portions of Algeria, Libya and Tunisia (Fig. 1). Hydrocarbon exploration started in the Basin in the 1950's with the Libyan sector being the most prospective [5]. Pre-1990 reserve was put at 3.5Billion Barrels of Oil Equivalent [BBOE] [6-7]. Between 1990 – 2000, additional 5-6 BBOE were discovered in the Algerian sector [7] consequent upon advancement in exploration (seismic) technology, and improved understanding of plays within the basin. Current proven reserves are in excess of 32BBOE occasioned by discoveries made within the Algerian sector [5]. The basin plays host to two prolific source rocks - the Silurian Tanezzuft Formation and the middle-upper Devonian Aouinet Ouinine Formation [8], which sourced the hydrocarbons (Tanezzuft: 80-90%; Aouinet Ouinine: 10-20%) pooled within the Cambro-Ordovician (dominantly gas) and Silurian-Devonian (oil and gas) plays [9]. These source units (especially the Tanezzuft Formation) are the targets for shale gas/oil exploration.

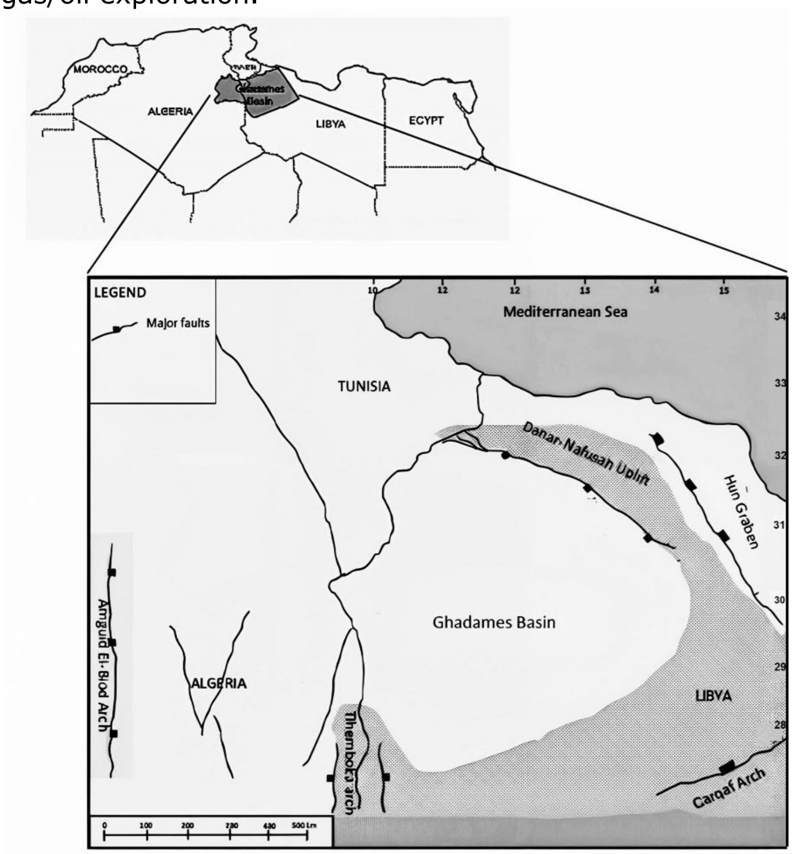

Fig. 1. Map of North Africa showing the location of Ghadames Basin. B, map of Ghadames Basin showing structural elements (after [14]).

It has been suggested that the potential for unconventional resources in the Ghadames Basin be evaluated [10-12] evaluated the potential for shale gas and shale oil. Their findings indicate some potential for shale oil and gas in the Ghadames Basin. The risked volumes of wet and associated gas are estimated to be 42.8Tcf and 176.2Tcf respectively [13].However, an understanding of the maturity profile from basin history analysis standpoint and its impact on gas adsorption potential is still sketchy. The objective of this research, therefore, is to undertake a preliminary assessment of the Tanezzuft Formation’s shale gas potential, using data obtained from wells in the Algerian and Libyan sectors of the basin, In addition, a burial history analysis of the Tanezzuft Formation will be carried out with a view to understanding its gas adsorption potential. In addition, the gas shale properties of the Tanezzuft Formation will be compared with the established Palaeozoic gas shales in the US.

2. Geological overview

The Ghadames Basin is a large polycyclic intracratonic sag basin (at present day) covering an area of about 350,000km^2 in North Africa encompassing parts of Algeria, Libya and Tunisia

(Fig. 2). It is bounded by the Dahar – Naffussah, Qarqaf uplift, and Hogar shield, Amguid – El Biod Arch, Sirte Basin in the north, south, east, and west respectively (Fig. 1). Basin initiation commenced in the early Palaeozoic, with sedimentary packages spanning from Cambrian to Neogene. The Cambro-Ordovician period was characterised by the deposition of continental sandstones, succeeded by deposits of marine transgression into the basin [8]. Widespread glacial activity over North Africa in the late Ordovician forced regression which halted marine conditions especially in the southern parts of the basin [14].

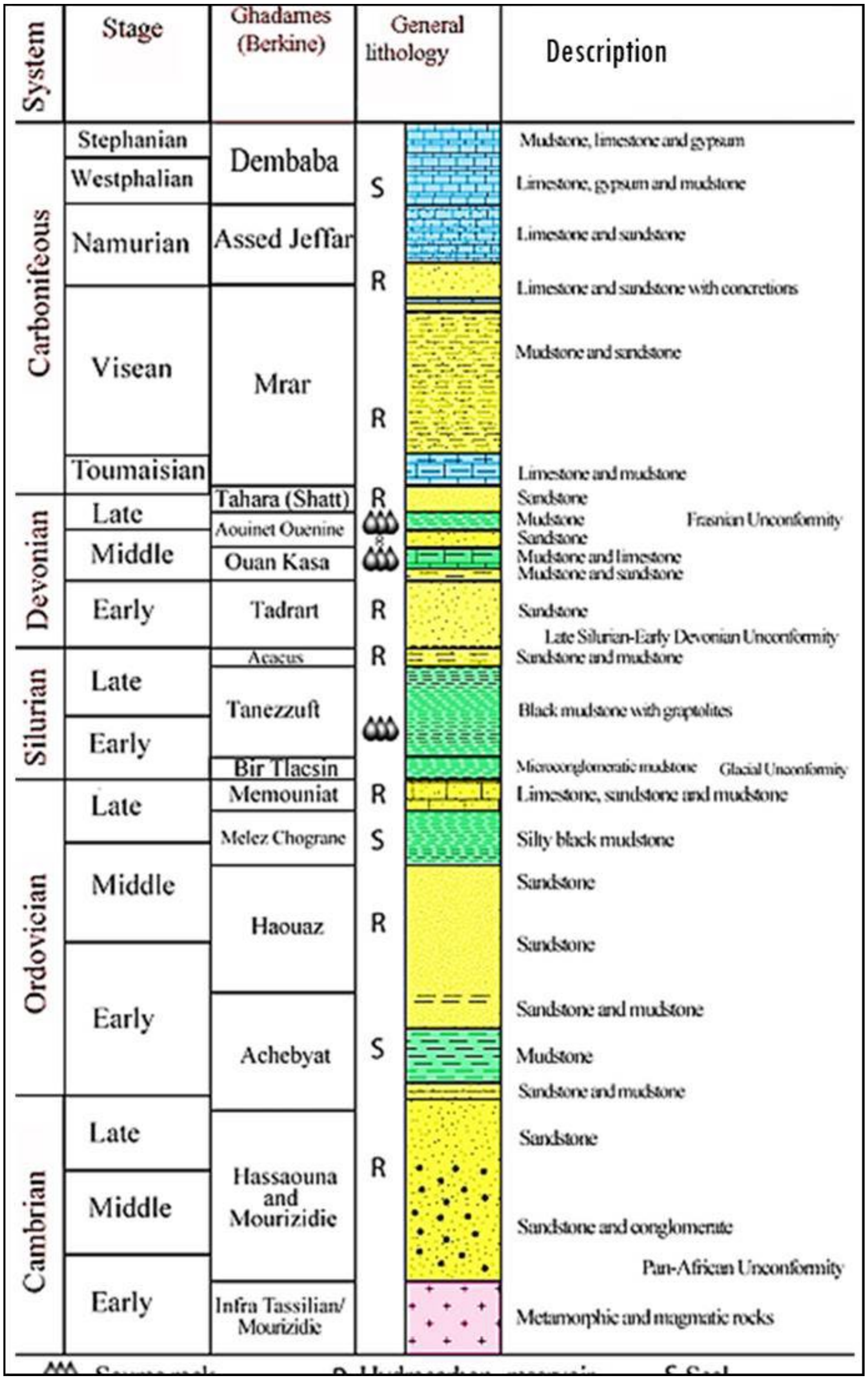

Fig. 2. Ghadames Basin Stratigraphy (modified after [12]).

The basin experienced localised uplift and exhumation of pre-Ordovician sediments and development of deep erosional valleys that were subsequently filled with glaciogenic sediments occasioned by the Taconic event. Syn and post Taconic sediment thickness and facies distribution within the basin were controlled by folding and faulting associated with this phase [6]. Following renewed subsidence during the Late Ordovician to Silurian widespread marginal marine to marine conditions became prevalent due to rising sea level arising from melting of ice, which resulted in large scale deposition of organic rich 'hot shales' at peak marine transgression into the basin. The deposition of sand and shale interbeds occurred during falling sea level. Uplift and erosion of early Paleozoic sediments occurred during the late Silurian-early Devonian due to the Caledonian event [6]. It is estimated that the degree of exhumation associated with the Caledonian event is greatest on structural highs along the northern and southern borders of the basin (i.e. Dahar Nafusah and Qarqaf Arch) and least in the central part of the Ghadames [5]. Sedimentation resumed in mid-late Devonian with the deposition of continental clastics and shallow marine sediments (more dominant) with organic-rich 'hot shales' deposited over the Caledonian unconformity during maximum flooding. Deposition of shallow marine, deltaic and continental sediments continued into the Carboniferous following sea level fluctuations. Sediment deposition was again truncated consequent upon the widespread Hercynian event, characterised by uplift and significant exhumation of Palaeozoic strata. Consequently, the Hercynian unconformity separates Palaeozoic strata from Mesozoic rocks.

During the Mesozoic Era, the Ghadames Basin experienced extension associated with the initiation of the Tethys sea and the central Atlantic [16] and later thermal subsidence arising from the regional northwest tilt and northward depocentre shift. In the early Triassic, sedimentation commenced with the deposition of continental sandstones on the Hercynian unconformity. Shallow marine sedimentation became prevalent towards the late Jurassic and marine evaporites were deposited with sediment thickness varying from about 1000 ft in the South to over 6000 ft in the North.

In the early Cretaceous, predominantly fluvial sediments were deposited as the basin continued to subside [5]. Sedimentation was truncated by the Austrian event, which was characterised by large scale uplift, tilting and exhumation. It is hypothesised that the timing of the Austrian event was contemporaneous with Hydrocarbon generation from Palaeozoic source rocks [5]. Following renewed subsidence in the Cenomanian – Eocene, marine sedimentation which was characterised by the deposition of carbonates was prevalent. However, this was stopped by the Alpine event. In the Pliocene, terrigenous sedimentation was prevalent.

2.1. Tanezzuft Formation

Large Scale flooding of southern Gondwana in the Silurian Period arising from sea level rise brought about by the melting of glaciers led to the deposition of the Tanezzuft Formation under a passive margin tectonic setting [6,9]. The extent of its deposition is hypothesised to have been controlled by the Sahara metacraton [5]. The Tanezzuft Formation has a variable thickness ranging from 200m over the Ahara Arch and in the Northeast to up to 1200m [17] in the western part of the Basin. The Tanezzuft Formation occurs as grey – green and red gypsiferous and laminated shales, intercalated with silt and fine sand. It is a prolific source rock with Type II kerogen, described as a 'double hot shale' [18] comprising a bottom hot shale with greater geographic spread, up to 120 m thick in the Algerian sector (western part) 1 with as much as 17% TOC and HI of 250-450MgHc/g, and better source quality [8], and an upper hot shale with similar properties as the bottom hot shale but restricted in terms of distribution. The 'double hot shales' are separated by poorer quality shale of similar composition. The best source rock quality and highest thermal maturity occur in the deepest part of the Palaeozoic depocentre [9]. Whereas regional data suggests very little compositional variability within the Tanezzuft Formation in the Ghadames Basin [19], thermal maturity is variable and increases from the North where it is immature to marginally mature, to the south and west where it is in the gas window [8]. However, regional fault structures with anomalous geothermal gradients can complicate these maturity trends.

3. Methodology

The methodology adopted for this study was fashioned after [20]. It involves basin screening which assesses geochemical and mineralogical data from the gas shales, and basin modelling which examines the burial and thermal history of the basin. A summary of the methodology is detailed in the workflow below (Fig 3).

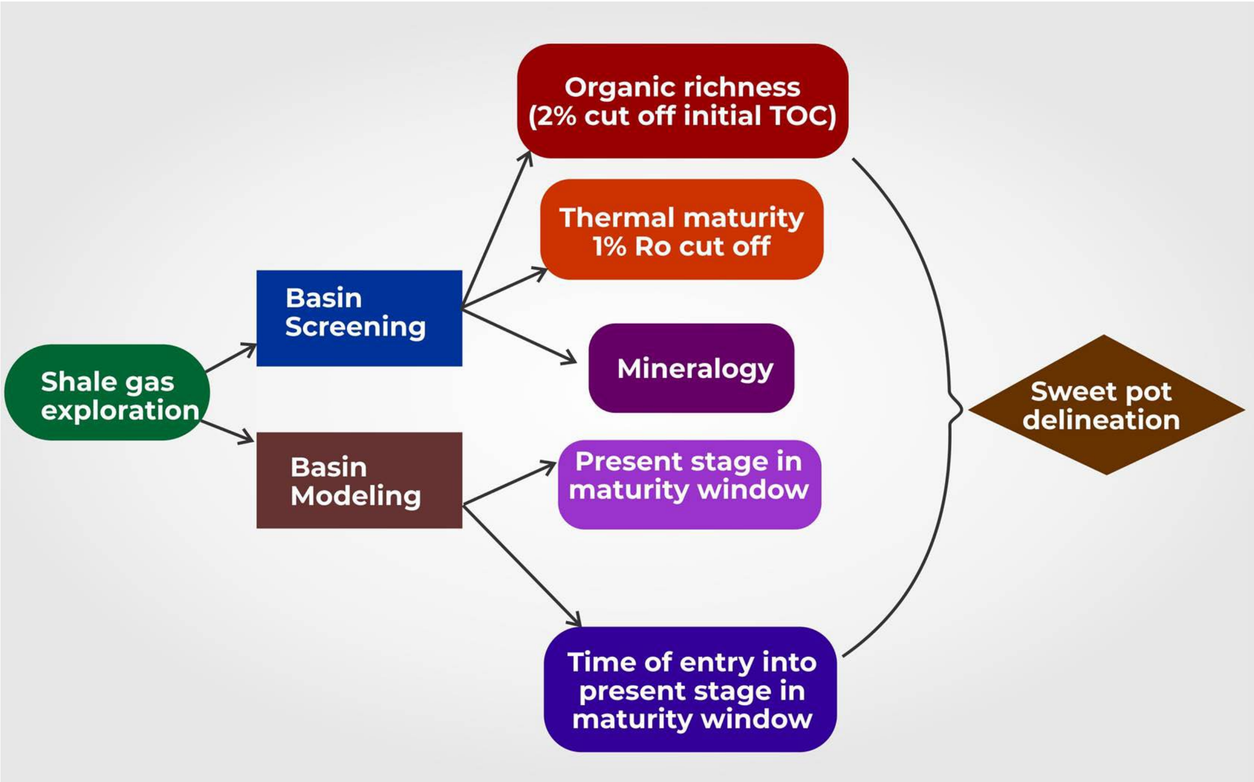

Fig. 3. Shale gas exploration workflow (adapted from [20]).

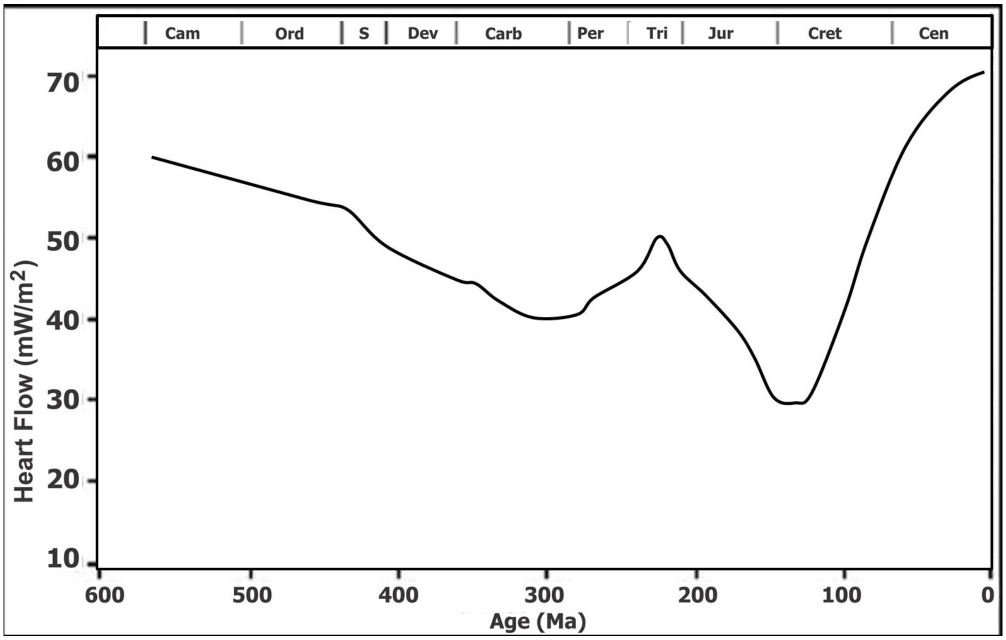

Fig. 4. Variable heat flow model used for basin modeling (adapted from [14]).

3.1. Basin screening analysis

TOC, Maturity, and HI data from 49 drilled wells were used to screen the basin. Some of this well data were extracted from existing publications [15-16]. Organic richness (TOC) and source quality (Hydrogen Index) generally reduces or is lost with hydrocarbon generation/expulsion [21]. Consequently, it was necessary to convert the present-day organic richness and Hydrogen index to initial organic richness and hydrogen index before carrying out basin screening. There are several ways of doing this, but the method postulated by [21] was employed as shown below:

$$TOCinitial = \frac{TOCmeasured}{[1-(F\Delta C)]} \tag{1}$$

$$F = HIinitial - HImeasured\,/\,HIinitial \tag{2}$$

where F is extent of HC generation; ΔC is maximum TOC loss for kerogen type;
Type I = 65%; Type II = 50%; Type III = 20%.

In addition, Tmax maturity data was converted to $R_{oequivalent}$ using the formula postulated by [22] as shown below.

$$Ro = 0.0180\ x\ Tmax - 7.16^{**}\ [23] \tag{3}$$

**- may be unreliable where S2 values are < 0.2(mg HC/g Rock).

3.2. Basin modelling analysis

Inputs from geology (such as the timing of basin initiation, sediment deposition history/stratigraphy, exhumation/erosion events, periods of non-deposition, periods of uplift, etc.), geochemistry (organic richness, kerogen type, permeability, and porosity), and geophysics (heat flow history, bottom hole temperature, etc.) were used as input materials for 1-D basin modelling (thermal maturity modelling) independently for two wells data within the identified 'sweet spot area' using BasinMod software. Some critical input parameters will be briefly discussed below.

3.2.1. Heat flow

We elected to use a transient heat flow model instead of a linear model because of the polycyclic tectono-stratigraphy. The heat flow model (Fig. 5) by [14] was selected as it had the best calibration with recorded thermal maturity data (R_0) (see Fig. 6).

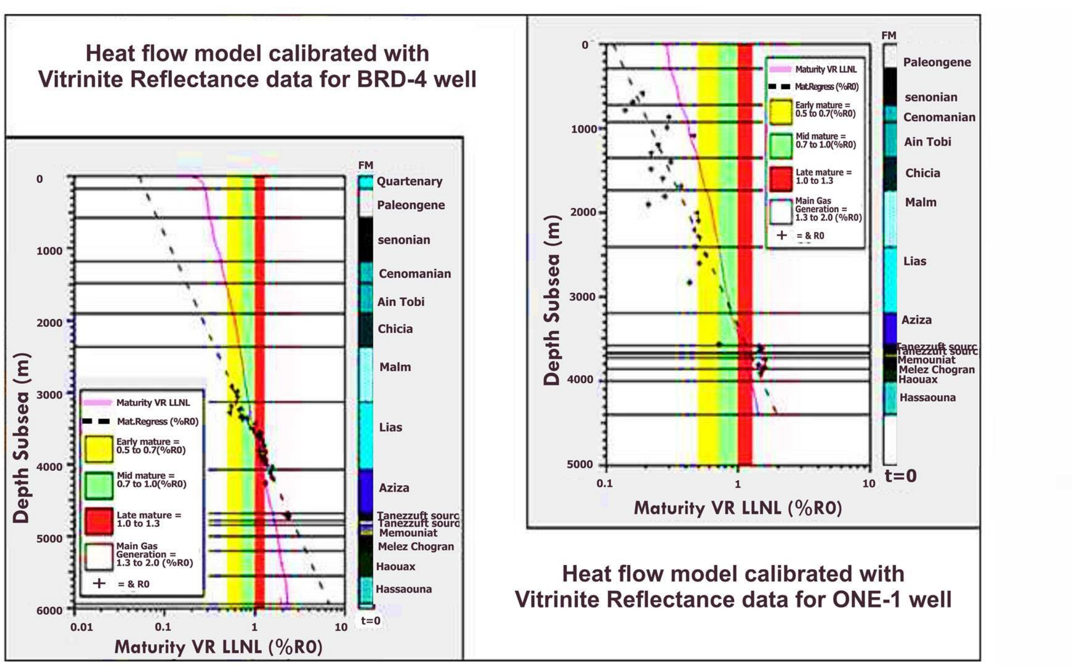

Fig. 5. Heat flow model calibrated with Vitrinite Reflectance for wells ONE-1 and BRD-4.

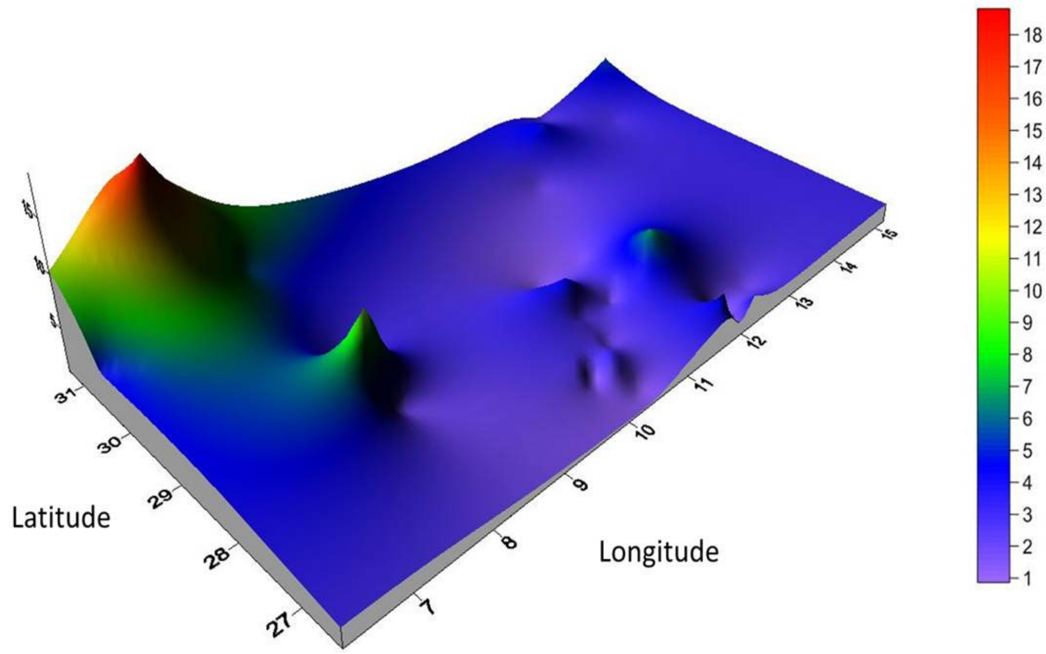

Fig. 6. Tanezzuft Shale initial TOC 3Dmap showing an increase towards the West/NW.

3.2.2. Thickness of exhumed strata

Constraining the thickness of exhumed strata especially due to the Hercynian, Austrian, and Alpine tectonic episodes is very critical in understanding the thermal maturity history of the Tanezzuft Formation. Reliable estimates (Table 1) were obtained after integrating data from [5,14].

Table 1. Estimates for exhumed overburden (after [5,14]).

Event	Begin Age (Mya)	Eroded thickness (m)
Alpine	36.7	100
Austrian	120	600
Hercynian	292	3600

4. Results and discussion

4.1. Sweet spot delineation

Organic richness varies from fair to excellent, Type II to Type IV kerogen, and immature to over-mature (Table 2). Maps of original TOC and R_{Oeq} (Figs. 7 and 8) show a trend of increasing TOC and thermal R_{Oeq} towards the West/NW. The R_{Oeq} (Fig. 7) trend agrees with the findings of [8] and could be attributable to a higher overburden thickness arising from the shift in depocentre towards the West and Northwest in the Mesozoic [6,24]. Other factors include high heat flows associated with regional faults [8] and magmatic activities occasioned by Hercynian tectonics [9]. The initial TOC and R_{Oeq} maps (Figs. 7 and 8) were thereafter merged, and a major area 'sweet spot' with good prospectivity was identified in the W/NW (Fig. 8). The mapped 'sweet spot' cuts across all three countries, although the largest portion lies within the Algerian segment of the basin. The key uncertainty associated with the identified sweet spot area is the non-availability of raw mineralogy data. Desirable petrophysical qualities and frackability of gas shales is a function of its mineralogy and hardness/brittle index. In established gas shale systems, the proportion of calcite, quartz, and feldspar (combined) desired commonly exceeds 40 % [20]. Notwithstanding the non availability of mineralogical data, useful deductions can be made from published reports. An estimate of up to 37% of non-clay proportion is hypothesised based on the findings of [25] up to 35% of quartz in the Tunisian sector (see Table 3)] and [12] [up to 37% of brittle minerals]. The reports by [13,26] indicate an average of 50% of non-clay minerals, which is significantly higher than the reports from the aforementioned authors. This implies that favourable petrophysical properties which promote frackability of the Tanezzuft gas shale abound.

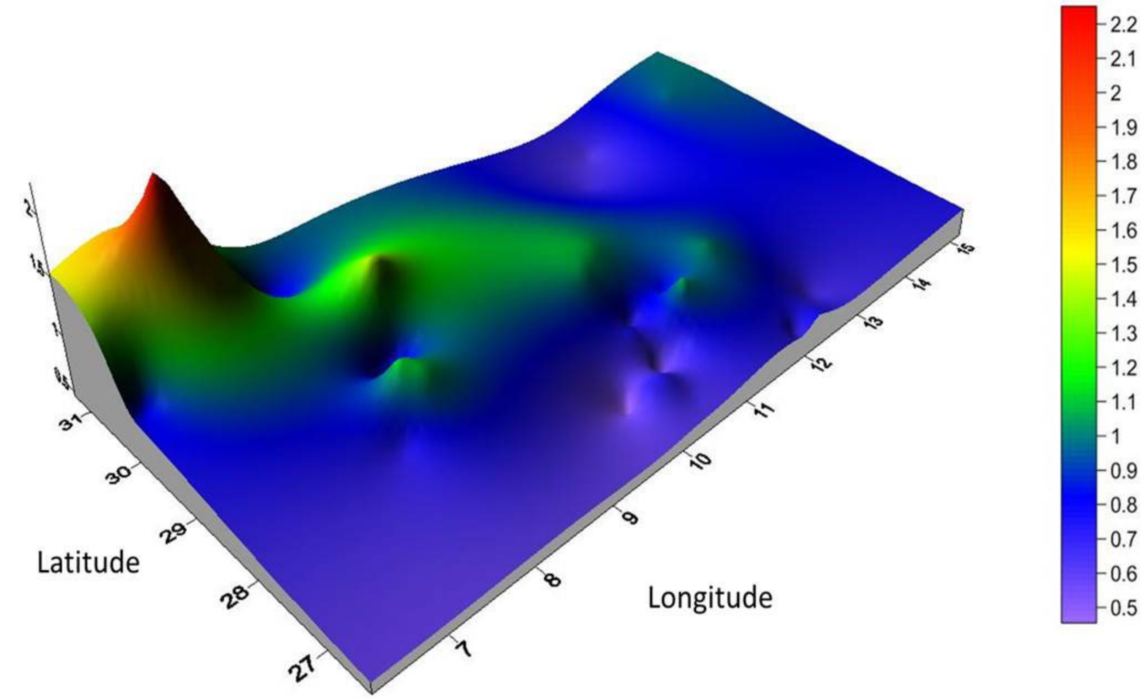

Fig. 7. Tanezzuft shale thermal maturity distribution map (R_{Oeq}) showing a West/NW increase in maturity trend.

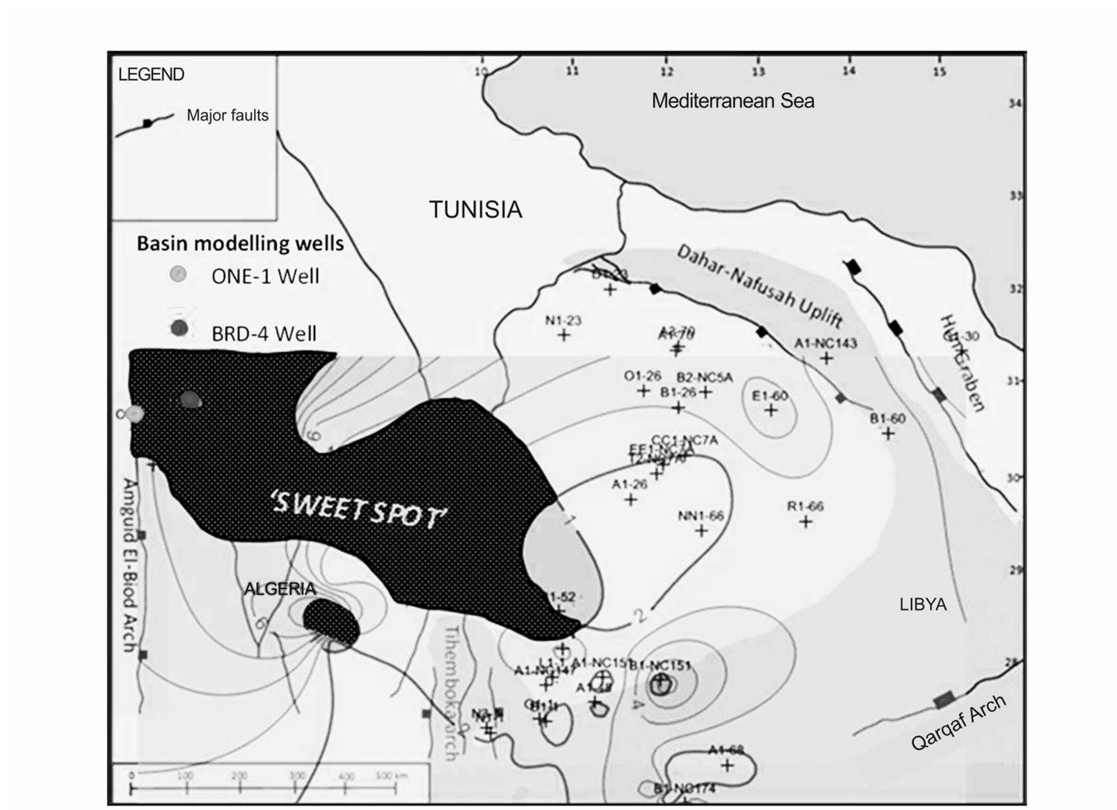

Fig. 8. Sweet ppot area inclusive of wells used for 1-D Basin modelling.

Table 2. Tanezzuft Formation source rock characteristics obtained from well data.

S/N	Well	TOC (wt.%)	$TOC_{Initial}$ (wt.%)	$HI_{initial}$ (mg HC/g TOC)	HI (mg HC/g TOC)	F	FΔC	Thick-ness (m)	Tmax °C	$Ro_{eq.}$ %	Petro-leum Poten-tial	Kero-gen type	Ma-turity
1	A1-1	0.83	0.89	193.15	182.64	0.05	0.07	-	432	0.62	Fair	III	Early mature
2	A1-48	1.76	2.58	188.06	68.34	0.64	0.32	13.11	457	1.07	Very good	III	Late mature
3	A1-61	0.84	-	-	290.92	-	-	-			Fair	II	
4	A1-68	1.40	1.51	118.04	111.62	0.05	0.07	22.25	432	0.62	Good	III	Early mature
5	A1-76	0.92	-	-	178.92	-	-	-	-	-	Fair	III	
6	A1-NC151	1.20	1.41	114.68	73.60	0.36	0.18	12.19	442	0.80	Good	III	Peak mature
7	B1-1	1.42	1.45	88.62	85.16	0.04	0.02	15.24	423	0.45	Good	III	imma-ture
8	B1-60	1.68	2.30	363.23	169.23	0.53	0.3	-	452.2	0.98	Very good	II	Late mature
9	B1-NC115	4.48	5.09	140.63	106.82	0.24	0.12	-	438	0.72	Excel-lent	III	Peak mature
10	B1-NC151	4.79	6.78	279.83	115.49	0.59	0.32	24.38	455	1.03	Excel-lent	II	Late mature
11	B1-NC174	3.42	4.02	196.44	137.84	0.30	0.15	21.34	440	0.76	Excel-lent	III	Peak mature
12	B2-NC115	0.72	0.77	297.62	256.52	0.14	0.07	-	433	0.63	Fair	II	Early mature
13	B3-61	0.54	-	-	109.12	-	-	-	-	-	Fair	III	-
14	B5-NC151	2.23	-	-	213.53	-	-	-	-	-	Very good	II	-
15	C1-49	1.10	1.44	182.46	85.01	0.53	0.24	-	450	0.94	Good	III	Late mature
16	C1-66	1.86	-	-	143.96	-	-	-	-	-	Good	III	
17	C2-NC115	0.54	0.63	509.35	357.41	0.30	0.15	-	440	0.76	Fair	II	Peak mature
18	D1-1	0.91	-	-	67.37	-	-	-	-	-	Fair	III	-
19	D1-60	6.38	-	-	7.05	-	-	-	-	-	Excel-lent	IV	-
20	D1-66	2.23	-	-	196.25	-	-	-	-	-	Very good	III	-
21	E1-1	2.13	-	-	75.98	-	-	-	-	-	Very good	III	-
22	E1-52	0.66	0.97	26.9	9.77	0.64	0.35	-	458	1.08	Fair	IV	Late mature
23	G1-1	1.99	2.09	118.98	107.44	0.10	0.05	13.72	429	0.56	Very good	III	imma-ture
24	G1-66	1.47	1.58	97.56	79.37	0.19	0.07	-	433	0.63	Fair	III	Early mature
25	H1-1	0.83	-	-	26.51	-	-	-	-	-	-		
26	K1-1	3.51	4.61	24.82	12.97	0.48	0.24	40.84	448	0.90	Excel-lent	IV	Peak mature
27	L1-1	1.79	1.98	96.24	78.30	0.19	0.09	26.52	434	0.65	Good	III	Early mature
28	M1-1	2.58	3.65	55.25	20.08	0.64	0.32	33.53	456	1.05	Very good	III	Late mature
29	M1-66	1.09	-	-	330.36	-	-	-	-	-	Good	II	-
30	N1-1	2.67	2.70	279.16	217.18	0.22	0.01	23.47	419	0.38	Very good	II	imma-ture
31	N3-1	2.27	2.32	202.92	194.99	0.04	0.02	28.96	423	0.45	Very good	II	imma-ture
32	O1-1	0.59	0.66	173.43	131.74	0.24	0.09	-	435	0.67	Fair	III	Early mature
33	EDY-5	1.00	1.47	-	-	0.68	0.34	-	458	1.08	Fair	-	Late mature
34	TZM-1	2.00	3.59	-	-	0.89	0.44	-	479	1.46	Very good	II	Post mature
35	AH-101	1.52	1.73	-	-	0.24	0.12	-	437	0.71	Good	-	Peak mature

S/N	Well	TOC (wt.%)	$TOC_{Initial}$ (wt.%)	$HI_{initial}$ (mg HC/g TOC)	HI (mg HC/g TOC)	F	FΔC	Thick-ness (m)	Tmax °C	$Ro_{eq.}$ %	Petro-leum Poten-tial	Kero-gen type	Ma-turity
36	IH-101	2.19	2.57	-	-	0.30	0.15	-	440	0.76	Very good	-	Peak mature
37	TAK-1	7.10	10.77	-	-	0.68	0.34	-	461	1.14	Excel-lent	-	Late mature
38	ADOE-1	4.30	4.89	-	-	0.24	0.12	-	437	0.71	Excel-lent	-	Peak mature
39	BRD-4	7.50	14.71	-	-	0.98	0.49	-	528	2.34	Excel-lent	II	Post mature
40	EKR-1	9.81	18.91	-	-	0.96	0.48	-	498	1.80	Excel-lent	III	Post mature
41	HSN-1	4.19	4.92	-	-	0.36	0.18	-	443	0.81	Excel-lent	III	Peak mature
42	ZK-1	5.42	6.16	-	-	0.24	0.12	-	438	0.72	Excel-lent	II	Peak mature
43	B5-NC151	2.84	3.23	-	-	0.24	0.12	-	438	0.72	Very good	II	Peak mature
44	C1-30	3.80	5.38	-	-	0.59	0.29	-	453.3	1.00	Excel-lent	III	Late mature
45	A1-NC143	1.70	2.07	-	-	0.36	0.18	-	442.2	0.80	Very good	-	Peak mature
46	E1-60	4.66	4.90	-	-	0.14	0.05	-	430	0.58	Excel-lent	III	imma-ture
47	ONE-1	2.50	4.24	-	-	0.82	0.41	-	470	1.30	Excel-lent	II	Late mature
48	ANR-1	4.00	-	-	-	0.24	0.12	-	437	0.71	Excel-lent	II	Peak mature
49	A1-NC147	2.10	2.47	-	-	0.30	0.15	-	440	0.76	Very good	-	Peak mature

Table 3. Comparison of Tanezzuft gas shale properties (sweet spot) with Paleozoic gas shales in the US.

Parameter	Target range	Utica	Marcellus	Tanezzuft (sweet spot)
Age	-	Middle–Late Ordovician	Middle Devonian	Silurian
TOC (wt.%)	>2%	0.5 – 3.0	2.5-5.5	0.5 - 17
Thermal maturity (% Ro)	>1.0%	0.3 - >1.0%	0.6 – 3.0%	1 – 2.2
Non clay content (wt.%)	40 – 80%	50%	19 – 56.5	Up to 37% [12]
Kerogen type	I/II	II	II	II/III
Thickness (m)	>30	>15	>8	Up to 60
Depth (m)	<4000	<4000	<4000	<5000

4.2. Basin modelling

Data from BRD-4 well and a pseudo ONE-1 well (Fig. 8) within the identified sweet spot area were utilised for the 1-D basin modelling. Input parameters have been detailed in section 3.2.

4.2.1. Burial history plot

Burial history plot (Figs. 9-10) reveals two maximum burial periods for the Tanezzuft Formation occurring in pre- and post-Hercynian orogeny. During the pre-Hercynian event, the Tanezzuft Formation attained a maximum depth of burial of 3700m and 3290m in wells BRD-4 and ONE-1 wells, respectively in the late Carboniferous (Figs. 9-10), whereas post-Hercynian burial depth of 3890m and 4700m in in wells ONE-1 and BRD-4 wells respectively was attained in late Palaeocene. It can be deduced that the Tanezzuft was buried deeper in the area around well BRD-4 in comparison to the more western located pseudo ONE-1 well, which perhaps explains the higher thermal maturity around BRD-4 well going by a geothermal gradient range of 22–45^{o}C/km which was has been postulated for this basin [27].

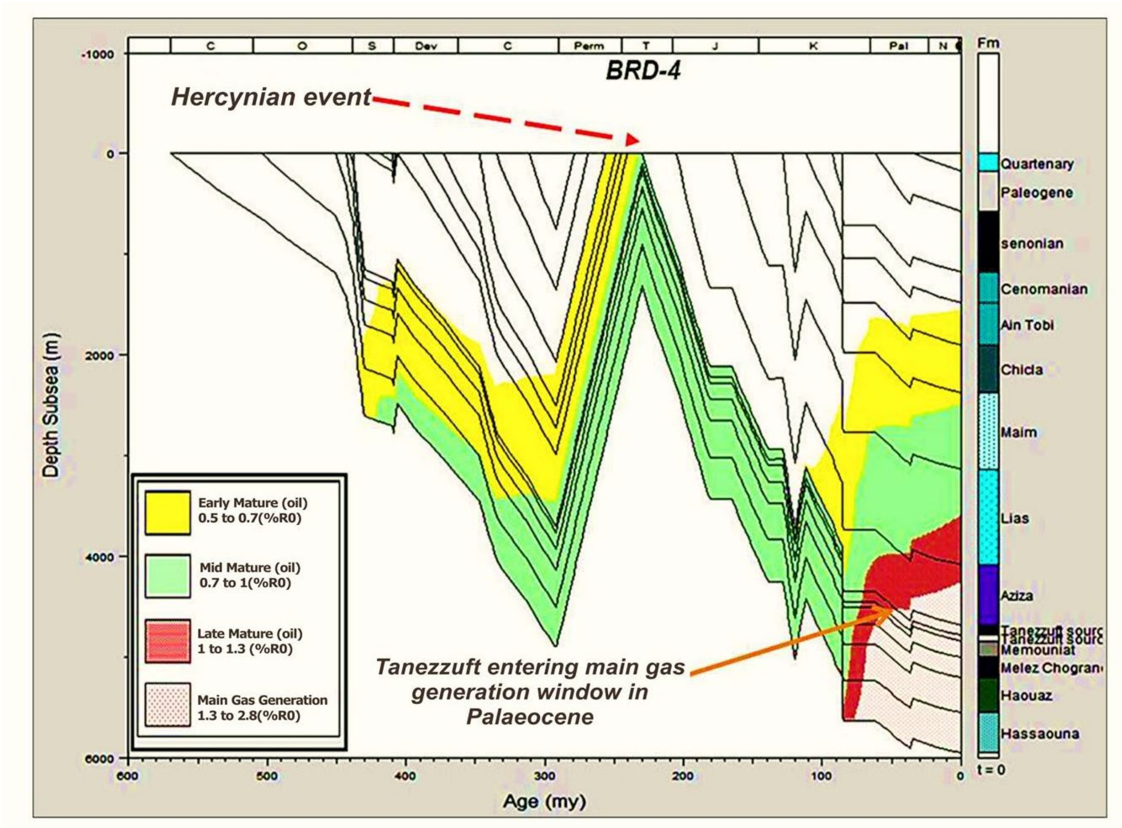

Fig. 9. Pseudo BRD-4 well 1D basin model showing maturation profile of the Tanezzuft Formation.

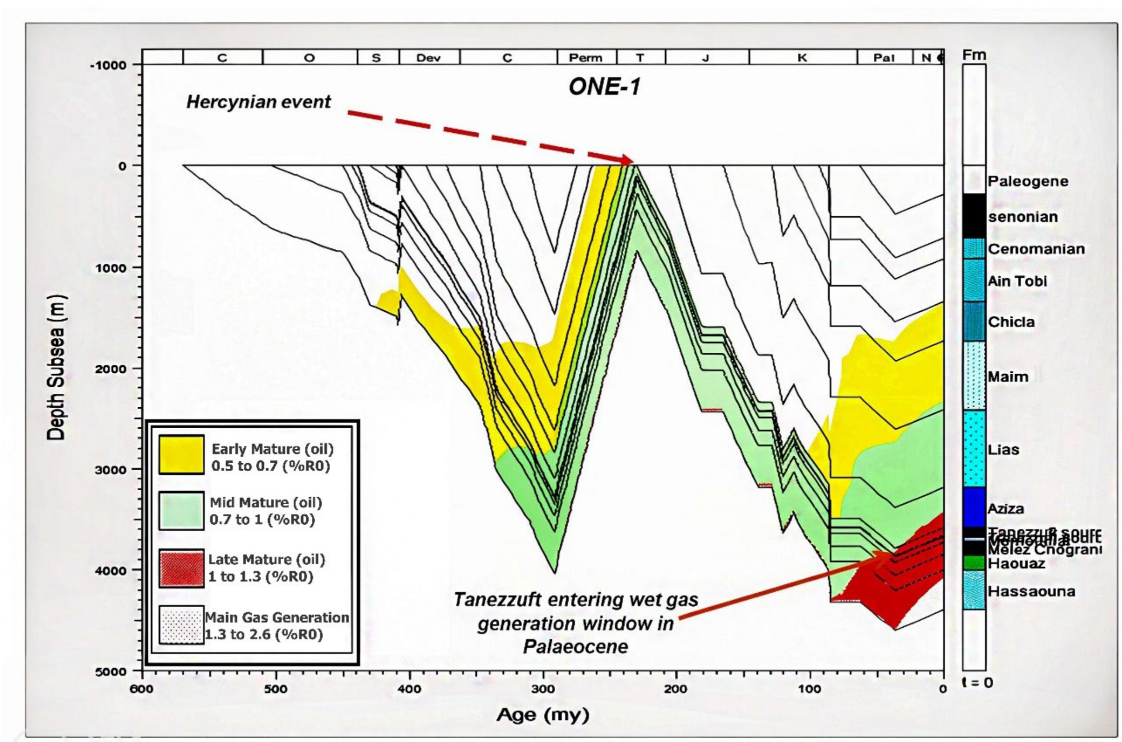

Fig. 10. Pseudo ONE-1 well 1D basin model showing maturation profile of the Tanezzuft Formation.

4.2.2. Hydrocarbon generation

The burial history plots for BRD-4 and pseudo ONE-1 wells reveal that hydrocarbon petroleum generation took place in two phases, which agrees with data published elsewhere [6,24]. Pre-Hercynian hydrocarbon generation commenced in the Mid Devonian (BRD-4)/Early Carboniferous (ONE-1). However, its length of exposure in the oil window was shortened due to the significant uplift and sediment exhumation associated with the Hercynian tectonic episode. Renewed basin subsidence in the post-Hercynian allowed for progression of organic matter maturation within the Tanezzuft Formation. Consequently, the Tanezzuft gas shale entered the main gas generation phase in the BRD-4 well area and wet gas generation window in the pseudo ONE-1 well area during the Mid to Late Palaeocene.

4.3. Shale gas potential

Modelling results reveal good potential for shale gas shale development in the sweet spot area, particularly around BRD-4 well location. In addition, the modelling results from the pseudo ONE-1 well show an upside for wet gas as well.. In addition, the attractiveness of the Tanezzuft gas shale is further enhanced by the shallow depth of burial (< 5000m), which imparts positively on the cost of drilling, moderate over pressure [13], which positively impacts on the flow rate of the well as well as the thickness of the gas shale (up to 60m) in the sweet spot area.

4.3.1. Adsorption potential

As confirmed by the burial history profile, the intensity of the Austrian and Alpine tectonic episodes were more significant in the East/ South east [14] of the basin (Fig. 9-11). Consequently, the subdued influence of the Austrian and Alpine tectonics on the post-Hercynian maturation profile of the Tanezzuft Formation in the western part of the basin makes the identified sweet spot area quite attractive for shale gas development. This is because there is great potential for adsorption and retention of thermogenic gas generated from Palaeogene to present day (Fig. 12).

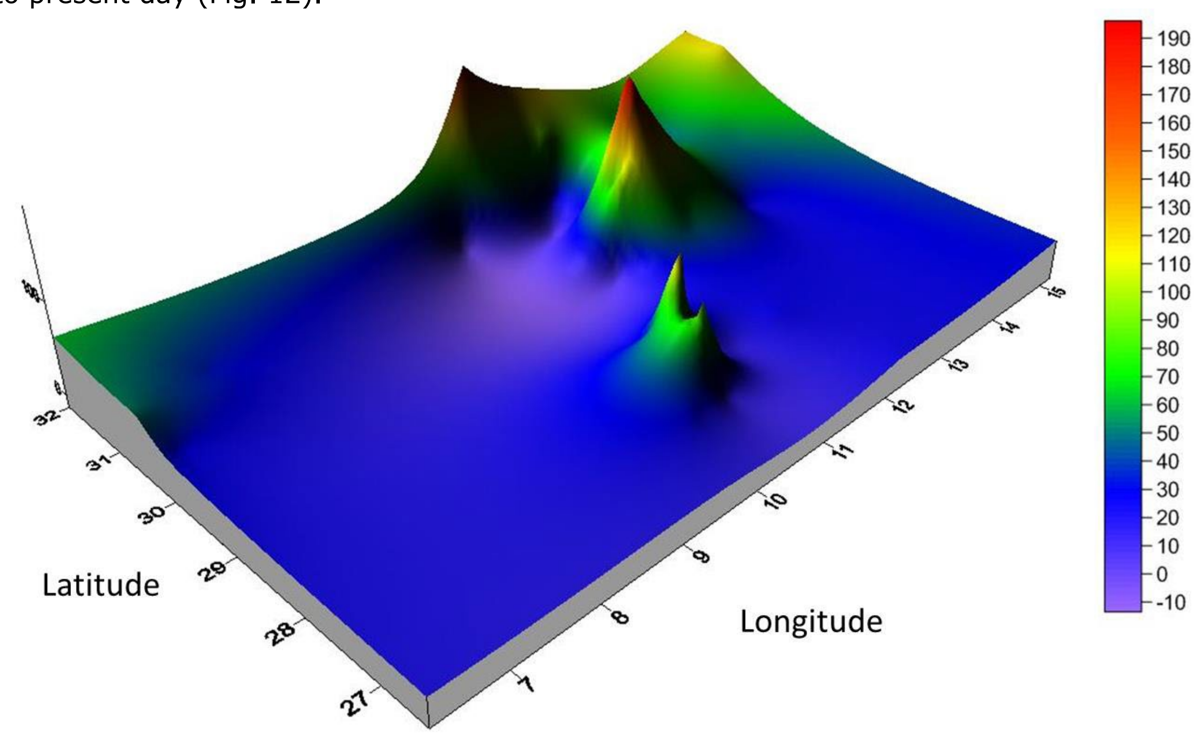

Fig. 11. 3D thickness map of the Tanezzuft gas shale based on available data.

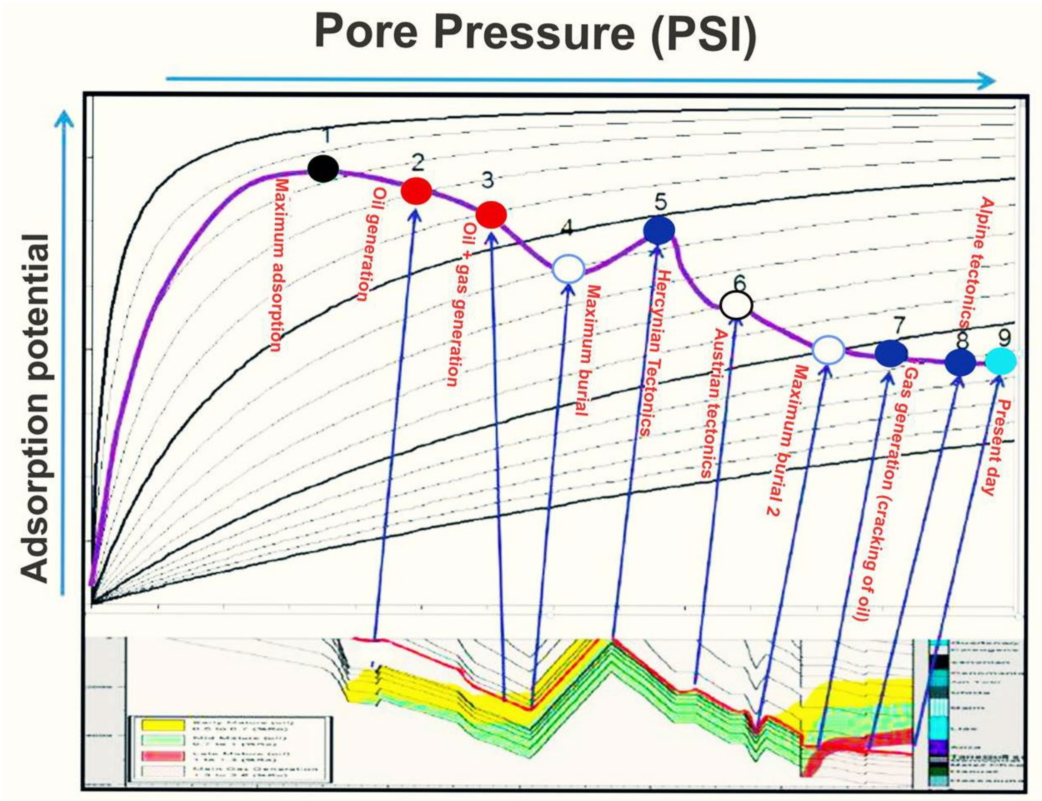

Fig. 12. Adsorption potential vs. temperature & pressure history (schematic).

4.3.2. Comparison with similar aged shale gas plays/additional considerations

An attempt was made to compare some properties of the Tanezzuft gas shale with some Palaeozoic gas shale plays in the US (Table 3). From our findings, it is clear that the Tanezzuft gas shale compares favourably with Utica and Marcellus gas shale plays. Furthermore, it is hypothesised that proven modern technologies for successful development of shale gas systems in the USA such as: horizontal well drilling and hydraulic fracking will be successful in the Ghadames Basin. Notwithstanding the good prospects for shale gas exploitation in the sweet spot area, non-technical issues such as the volatile nature (insecurity) in recent times in Algeria and Libya, access to technical support as well as the political will (or lack of) [13] water supply for fracking operations. Estimates of water resource requirements for one fracking job is 9-29 million litres [28]. In addition, potential environmental issues such as methane emission, groundwater contamination with high percentages of methane and 'flow back liquids' which may be due to leaking casings, old uncased wells, etc. [28] and seismic activity arising from injection of fracking fluids, need to be carefully evaluated before successful exploitation of this important resource can be achieved .

5. Conclusion

Western Ghadames Basin has the right thermal maturity (i.e.≥1.0% Ro) and initial TOC (i.e.≥2% initial TOC) mix suitable for shale gas exploration. A 'Sweet spot' for shale gas development exist in the western Ghadames Basin 1-D Basin modelling result for BRD-4 well and pseudo ONE-1 well in the identified 'Sweet spot' reveal favourable thermogenic gas adsorption potential of the Tanezzuft gas shale Tanezzuft gas shale compares favourably with established shale gas plays in the US.

Declaration of interests

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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