Research Article

Petrophysics and Nuclear Magnetic Resonance (NMR) study of low-resistivity pay in Lower Silurian sandstones reservoir in the Ghdames Basin

Lazzez Marzouk

1- Entreprise tunisienne d'activités pétrolières, ETAP, 54 avenue MED V. BP 1002 Tunis Belvédère, Tunisie.

E-mail: lazzez.marzoug@laposte.net

Abstract

Knowledge of reservoir evaluation is helpful in the interpretation of well-logging data, where the hydrocarbon saturation is expected as the final result by Archie equation. It is calculated from the deep resistivity, water formation resistivity and porosity. Porosity is calculated from the bulk density, neutron and sonic are measured directly in the well. The Archie evaluation, in the low resistivity layers, is characterized by high water saturation. The MDT tests in the low resistivity pay prove several oil samples. For this incompatibility interpretation of low-resistivity-contrast pay zones needs an analysis of the reservoir composition in the study area. The divergence results between Archie and well test allow integrating a new evaluation approach. However, the proposed interpretation framework does allow the incorporation of new logging technology as this becomes established. Nuclear magnetic resonance (NMR) is a useful tool in reservoir evaluation. The objective of this study is to predict petrophysical properties from NMR $T2$ distributions. The evaluation of NMR relaxation time distributions estimates of pore-size distributions. Irreducible water-saturation estimates from NMR-based pore-size distributions. In this study, we look at the down hole NMR measurements to determine pore geometry and volumetrics within a reservoir (free fluid index). NMR measures the net magnetization of a hydrogen atom (H) in the presence of an external magnetic field. Hydrogen has a relatively large magnetic moment and is abundant in both the water and hydrocarbons that exist in the pore space of sedimentary rocks. NMR measurements provide information about the pore structure (Sp), the amount of fluid *in situ (FFI),* interactions between the pore fluids, and surface of pores and provide important information for evaluation of low-resistivity layers.

Keywords: reservoir evaluation, well-logging data, hydrocarbon saturation, Archie equation. MDT tests, Nuclear magnetic resonance (NMR).

INTRODUCTION

The Ghadames Basin (Figure 1) is an established oil province. The reserves are spread over a large range of siliciclastic reservoirs extending from Cambrian to Middle Triassic. It forms the southern part of the Trias/Ghadames Province 2054 which is differentiated into three sub-provinces. The Ghadames Basin is confined by the Talemzane-Gefara Arch in the North, the El Gassi-Hassi Messaoud Ridge in the NW, the Amiguid-Hassi Touareg Axis in the SW, the Illizi Province in the south and the Hamra Basin to the East (Klett, 2000 and other authors include the Hamra Basin as part of the Ghadames depression (Dardour et al., 2004).

In unconventional reservoirs, low-resistivity pay zones are usually associated with one or more of the following: laminated reservoir/non-reservoir sequences, formations with multimodal pore-size characteristics, sediments with anomalously high surface area, and electronically conducting minerals. In all these cases, hydrocarbons have been produced with little or no water cut in the presence of high interpreted water saturations, in many different parts of the study area. It is therefore important to have a generalized facility for recognizing low-resistivity pay
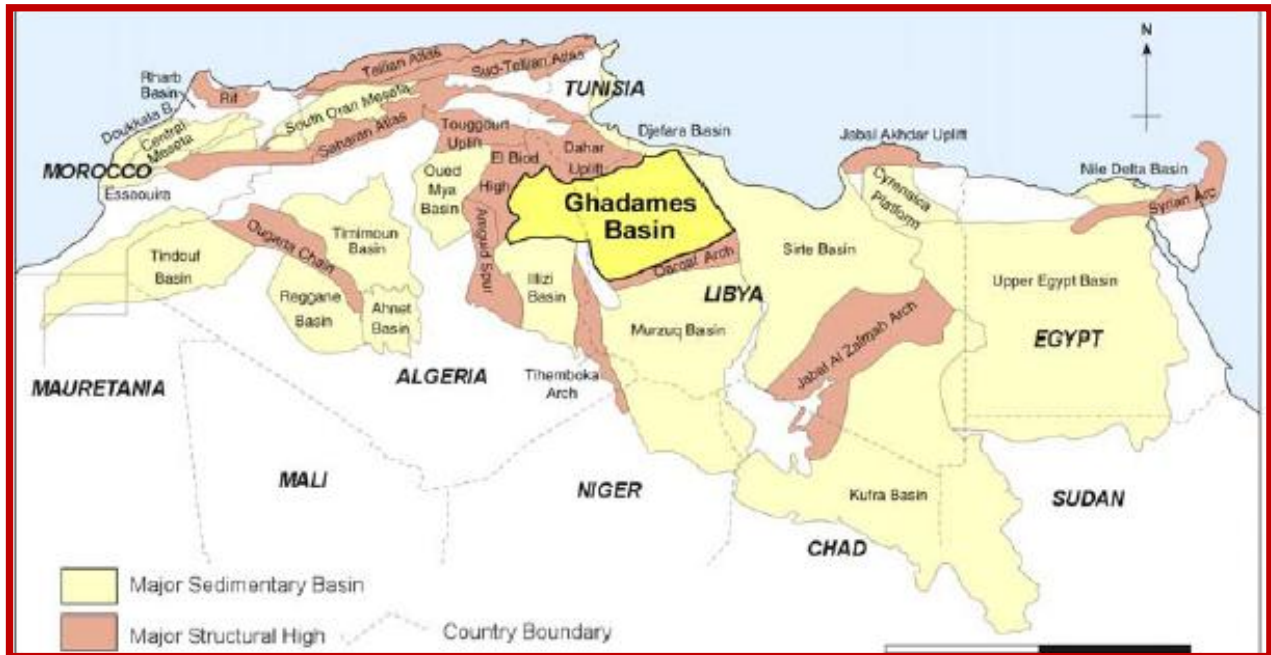
Figure 1. Extension of Ghadames Basin throughout Libya, Tunisia and Algeria
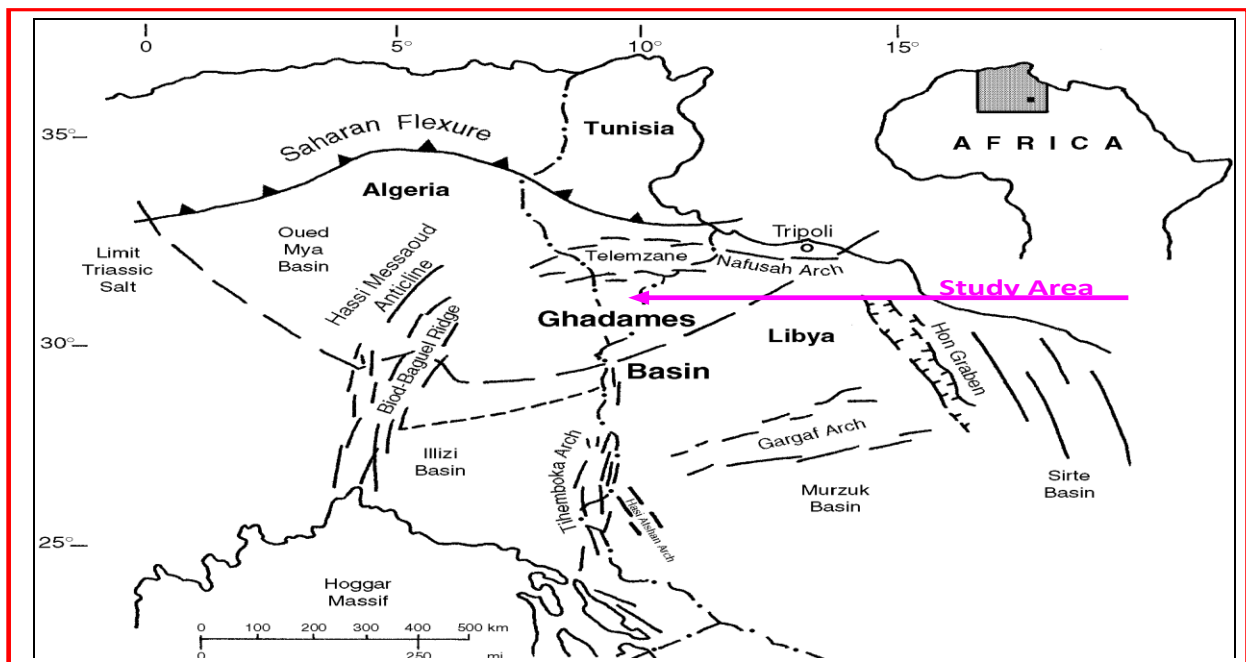

Figure 2. North Africa regional map includes parts of eastern Algeria and western Libya showing location of the Ghadames basin in southern Tunisia (Petroleum Geology ETAP 2004)

as early as possible in the life of a prospect. The problem of identifying low-resistivity pay through wireline log analysis has been acknowledged for over 30 years. This study need integration of petrophysical data with stratigraphic models to improve exploration success has been noted in previous studies. In mature petroleum provinces, where exploration and production strategies merge, detailed understanding of petrophysical properties in reservoir systems can be critical to delineating commercial and noncommercial prospects and in designing optimum reservoir management practices. To develop better models of reservoir distribution and properties in Lower Silurian reservoirs of the Ghdames basin, this study integrates rock petrophysical properties, facies analysis, integration of NMR and logging investigation which has been not accomplished in the past.
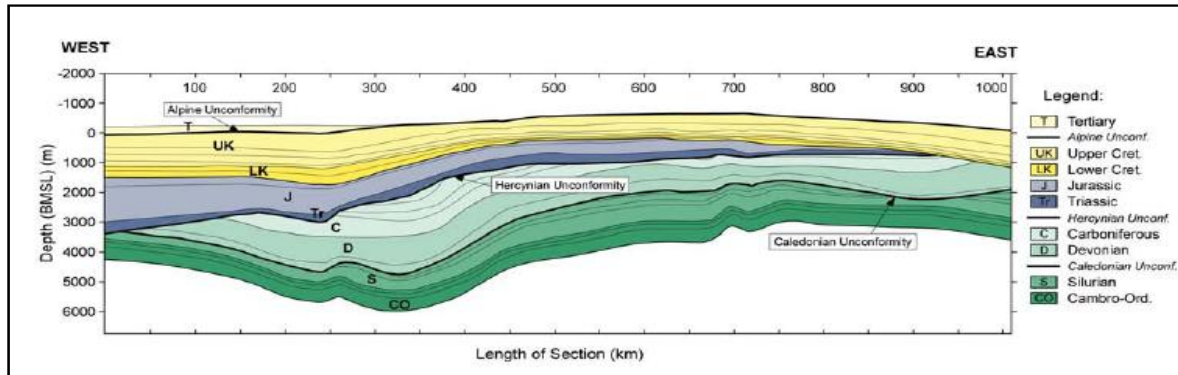
Figure3. W-E cross-section across the Ghadames Basin showing the regional angular Hercynian unconformity. (Petroleum Geology ETAP 2006)
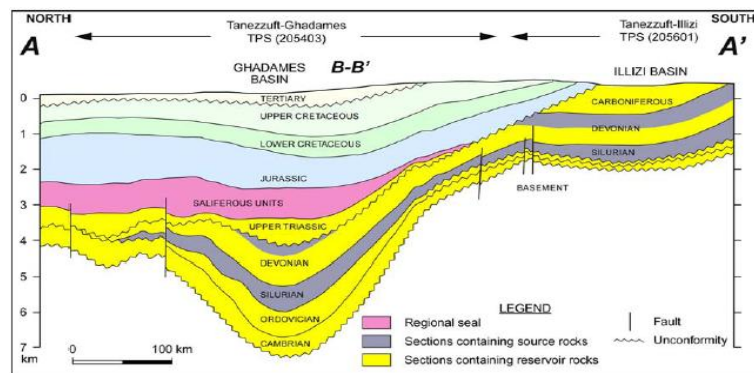

Figure 4. N-S cross section through the Trias/Ghadames and Illizi Provinces (Petroleum Geology ETAP 2006)

This study of the Acacus Sandstones have been developed based petrogrphic descriptions of the cuttings, petrophysical analysis and NMR study of 15 wells covering Acacus A Sandstone.

GEOLOGY OF THE GHADAMES BASIN

Tectonic history

The Ghadames Basin forms a large intracratonic structure on the North African Platform and is part of the Sahara Platform formed during the Early Palaeozoic. It is surrounded by fault-bounded structural highs. Major Uplifts are the Dahr-Nafusah Uplift, Qarqaf and Tihemboka Arches, the Hoggar Shield to the South and the Amguid-El-Biod-Arch. The Basin covers an area of 350,000km^2, across Libya, Tunisia and Algeria and contains up to 6000m Palaeozoic and Mesozoic sediments (Figure 2). The Silurian sequence is well known to the south of the Telemzane Arch, where it is divided into two formations in Ghdames basin where we found the Shale of Tannezuft and the Sandstones Acacus formations.

The Ghadames Basin evolved very roughly in three main stages (figure 3)

1. Predating the Hercynian Orogeny, the North African Platform was one large subsiding depositional basin, displaying little regional differentiation
2. Hercynian uplift and exhumation
3. Renewed subsidence during the Mesozoic led to NW tilting of the eroded remnants of the Palaeozoic Basin.
4. Renewed uplift during the Late Cretaceous and Early Tertiary (Alpine Orogeny)

Regional stratigraphy study

The Silurian sequence is well known to the south of the Telemzane Arch, where it is divided into two formations in Ghdames basin where we found the Shale of Tannezuft and the Sandstones Acacus formations. The Tannezuft
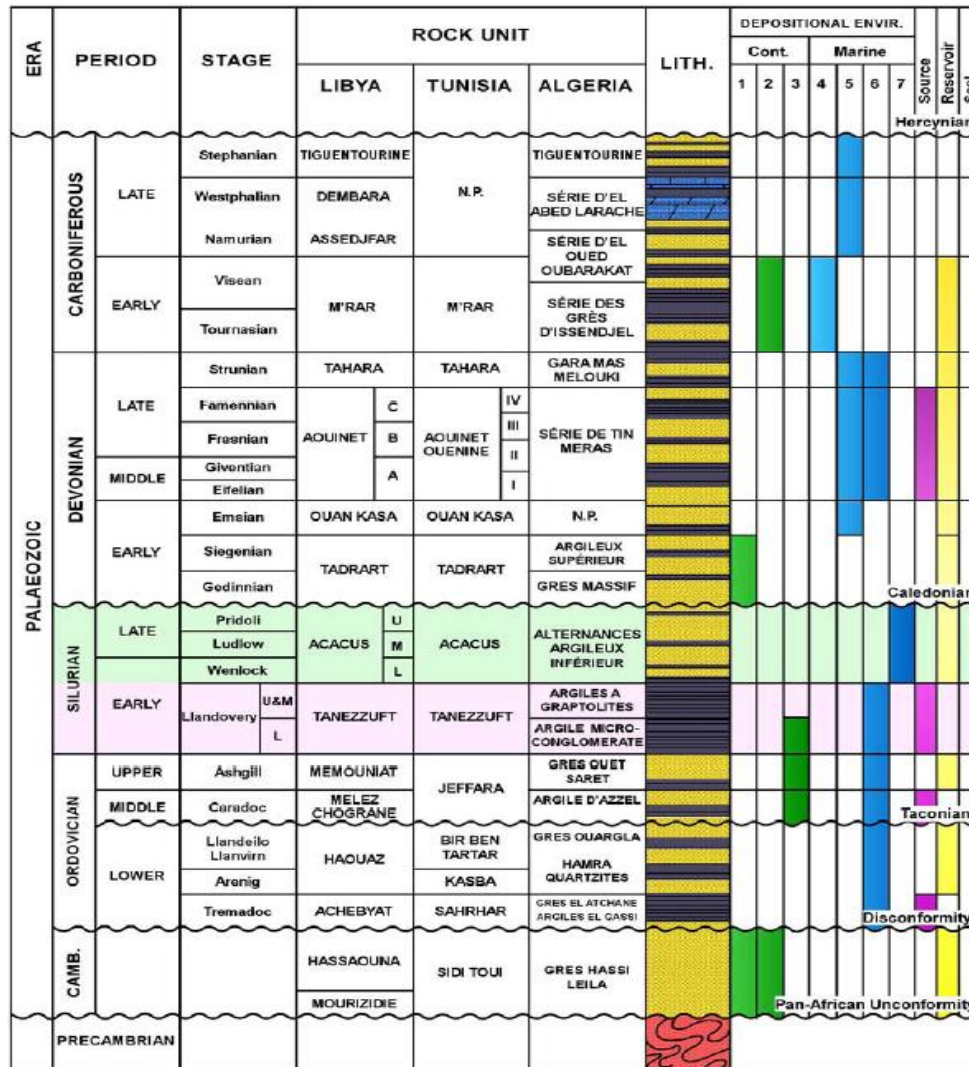
Figure 5. Palaeozoïc Stratigraphic Chart of Ghdames basin showing Reservoir rocks (RR), source rocks (SR) and seals(ETAP 2004)

Formation consists of basal, thin sequence fine-grained quartz sandstone. Upwards, the Tannezuft becomes better-off silty claystone, grading into shale, marl and dark, marly limestone. The top of the sequence is often missing below the Hercynian unconformity. The lower part of the Tannezuft is rich in organic matter with good source-rock characteristics. Sea level rise at the end of this period caused rapid flooding of the African Platform and deposition of a marine-shale dominated facies, peaking in an anoxic event with extensive organic-rich shales (Tannezuft Shales).

The lower 20-100m are very rich in organics and provide a good source rock. Subsequent deposition of the Acacus Sandstone indicates continuous shallowing during the rest of the Silurian, followed by regressive highstand sediments in the Upper Silurian (Acacus Sandstone) with a rapidly northerly prograding coastal shelf edge (Figure 4).

Hydrocarbon accumulations in the Acacus reservoir have been charged from a basal Silurian (Tannezuft) hot radioactive shale source rock. The Acacus Sandstone provided regional migration conduits sealed by intra-Acacus shales, silt- and cemented sandstones.

Hydrocarbons trapped prior to the Hercynian event were dispersed during later periods of deformation.
Most, if not all oil- and gas fields are supposed to have charged during the Late Cretaceous-Early Tertiary. So, the Alpine exhumation had particular impact on the Silurian source rocks in the eastern and southern parts of the basin (Figure 4).

During Cambrian times, continental clastics, mainly fluvial sandstones were deposited. This was followed by a marine transgression during the Ordovician, with massive marine mudstone deposits. During the Late Ordovician, marine conditions prevailed to the north, whereas further to the south a periglacial environment was established.

Towards the SE these sediments are truncated against the Caledonian unconformity (Figure 4). The Caledonian

Unconformity separates the Silurian from the Devonian successions.

Early Devonian successions are continental mud- and sandstones of the Tardrart Formation and are overlain by shallow marine sandstones and mudstones of the Ouan Kasa Formation. Continued transgression caused the deposits of argillaceous marine sediments of the
Aouinet Ouenine Group. Late Devonian to Carboniferous shallow marine sediments is a first indication of the Hercynian Orogeny (collision between peneplanation resulted in the Hercynian Unconformity.

The Palaeozoic Basin plunges northwards (Figure 4) and westwards and is unconformably overlain by a thick wedge of Mesozoic clastics, carbonates and evaporites, providing a reservoir and seal for a number of large The Palaeozoic Basin plunges northwards (Figure 4) and westwards and is unconformably overlain by a thick wedge of Mesozoic clastics, carbonates and evaporites, providing a reservoir and seal for a number of large hydrocarbon accumulations.

Deposits study of silurian formations in Ghdames Basin

The Silurian sequence is well known to the south of the Telemzane Arch, where it is divided into two formations in Ghdames basin where we found the Shale of Tannezuft and the Sandstones Acacus formations. The Tannezuft Formation consists of basal, thin sequence fine-grained quartz sandstone which rests on Ordovician sediments. Upwards, the Tannezuft becomes better-off siltyclaystone, grading into shale, marl and dark, marly limestone. Graptolites, chitinozoans, acritarchs and spores yield a Liandoverian to Wenlockian age. The top of the sequence is often missing below the Hercynian unconformity. The lower part of the Tannezuft is rich in organic matter with good source-rock characteristics.

The overlying Acacus Formation consists of interbedded shale and sandstone. The rock unit ranges up to 800 meters thick, and is often divided into members A, B and C. Graptolite faunas yield a date of Ludlovian to Pridolian age. The Acacus sandstone functions as an oil reservoir at several small fields in Libya as well as at Oued Zar and Hamouda fields in far southern Tunisia.

The transition from Tannezuft upwards into the Acacus is often gradual, slowly grading upwards into sandstone. In the Chott area, only the Upper Silurian is present. This sequence, called the Fegaguira Formation, consists of a shale succession with siltstone and rare sandstone. The Fegaguira is interpreted as a shaley equivalent to the Acacus. It has been suggested that the Fegaguira nomenclature be dropped as unnecessary.

Few wells have penetrated the complete section. Maximum thickness of the Silurian is 1100 meters, as described in the OZ-1 well. This thick rock unit is preserved in the Jeffara area at LG-1, but is eroded near the south flank of Telemzane Arch. In summary, the Tannezuft shales are interpreted as low energy marine sediments. The overlying Acacus sequence ranges from sublittoral marine to deltaic (Figure 5).
Gondwana and Laurasia). Subsequent erosion and

Characteristics of acacus reservoir and relationship with low resistivity

The greatest problem is recognizing that low-resistivity pay is actually present The causes of the four possible manifestations of low-resistivity pay take the form of coupled elements of a physico-chemical system that encompasses rock type, matrix properties and texture, clay-mineral properties and texture, grain size f coupled elements of a physico-chemical system that encompasses rock type, matrix properties and texture, clay-mineral properties and texture, grain size and contour, pore size(s) and pore geometry, and saturating water salinity. The causes can therefore be seen as components of the low-resistivity pay problem. The facies investigation possible causes of low-resistivity pay, each of which can be seen as a category of the subject area from a petrophysical perspective. The laminated sand/shale sequences and thin hydrocarbon-bearing beds can be grouped within low-resistivity zones where the geometry of the reservoir layers is such that they cannot be resolved by the logging tools that have been deployed. The previous illustrates the changing nature of the problem, because as higher-resolution resistivity tools are developed, some low-resistivity pay sands power become resolvable. The high salinity reservoir water formation can be a cause of low resistivity but low electrolyte salinity also allows the shale term to assume relatively large values, which make the accurate quantification of this term especially important. The electronic conduction within the rock matrix; this phenomenon usually arises where the concentration of a metallic mineral exceeds a critical level, beyond which it can act as a significant additional conductor. The next three causes, fine grains and internal or superficial microporosity, are all concerned with high capillarity. All three give rise to a high surface area, which can appear as a shale effect, especially if the formation waters are salt. This last comment emphasizes the coupled nature of the low-resistivity pay problem (Van de Weerd et al., 1994; Archie, 1942; Howard, 1998; Lafargue *et al.*, 1988; Leythaeuser and Rückheim, 1989; Leythaeuser *et al.*, 2000).

Nature of low-resistivity pay

In the first manifestation the low measured resistivity is indicative of water-bearing strata. The reservoir layers within the hydrocarbon leg may not be directly resolvable by wireline logging tools. This is an important point because; in this context of low-resistivity pay referred to the Archie equation. In the Sandstone reservoir we cannot distinguished electrically oil from water-bearing strata within the same reservoir system. The resistivity may not be low in absolute terms, but the resistivity contrast between the hydrocarbon and water legs is small. In cases where they can be resolved, the decisive factor for this manifestation is applied to the individual reservoir layers (Leythaeuser and Rückheim, 1989; George *et al.*, 2007; Grantham *et al.*, 1988 and Gray, 1987, Troll, in A M Spencer, M T Thomas, A G Doré, P C Home, and R M Larsen). Even where the hydrocarbon and water legs can be distinguished by wireline logs, but the quantitative petrophysical interpretation is grossly pessimistic because the physical characteristics of the reservoir rock extend beyond the range of applicability of the available interpretative models. This outcome may not be a sole consequence of the factors causing the low resistivity. This manifestation come to mind where a (high) water saturation can be evaluated correctly from the (low) formation resistivity, but the interpretation is incompatible with production characteristics, which show good moveable hydrocarbons (Van de Weerd *et al.*, 1994; Busch *et al.*, 1987; Quirein *et al.*, 1986; Hedberg et al., 1993; Howard, 1998; Lafargue and Barker 1988; Leythaeuser *et al.*, 1989; Leythaeuser *et al.*, 2000).

Formation water salinity

The first requirement is to classify the reservoir as an Archie reservoir. In this reservoir satisfies the requirements of low clay mineral content and high-salinity formation water above limiting water saturation (Archie 1942). In this and the following sections, it is assumed that direct evaluation of wire line logs is possible but with higher water saturation; the reservoir layers are sufficiently thick to be resolved by conventional logging tools.

Fresh formation waters can render hydrocarbon-bearing layers indistinguishable from water-bearing zones. There is no general limiting salinity which standard interpretation methodologies break down. Indeed, reservoir rocks and their interstitial waters show a continuum of electrical behaviour, where by a given interpretative algorithm can cease to be valid at any point within a range of formation-water salinities, depending on the electrochemical properties of the porous medium (Van de Weerd *et al.*, 1994; Busch *et al.*, 1987 ; Quirein *et al.*, 1986; Hedberg *et al.*, 1993; Howard, 1998; Lafargue *et al.*, 1988; Leythaeuser *et al.*, 1989; Leythaeuser *et al.*, 2000). Having stated this, most problematic situations do arise when the formation water salinity is less than about 15 000 ppm equivalents NaCl. Reservoirs that contain fresh formation waters are described as 'freshwater reservoirs'. This technique uses the basic Archie equations for the evaluation of water saturation, but the exponents that characterize these equations are allowed to assume very different values from the values $m = n = 2$ proposed by Archie (1942) [Archie, G E, 1942].

Conductive minerals

The presence of conductive minerals is the least cited cause of low-resistivity pay. The root of the problem is electronic conduction due to iron-bearing minerals that occur in clusters and whose concentration exceeds a critical level, taken by several Authors (Van de Weerd *et al.*, 1994; Leythaeuser *et al.*, 2000) for the case of pyrite as 7% by volume of the total solids. Another mineral that has been grouped in this category is glauconitic, which can in many respects be regarded as a clay mineral. However, here it is seen as iron-bearing mica with a potential excess conductivity (Howard, 1998; Lafargue *et al.*, 1988; Langhi *et al.*, 2010; Laubach, 1988: Leythaeuser *et al.*, 1989: Leythaeuser *et al.*, 2000) over and above any conductivity enhancement due solely to textural effects.

Conductive minerals can co-exist with other causes of low-resistivity pay. In the context of conductive minerals, the low-resistivity pay problem reduces to correctly evaluating the water saturation. There could still be a problem, because conductivity enhancement by clusters of iron-rich minerals might only become significant in the wet state. In this case, the concentration of the metallic minerals should be investigated to see if it is supercritical.

Fine-grained sands

In the context of fine-grained sands, the low-resistivity pay problem has two expressions. First, the fines can act as a separate mineral even if they are comprised principally of quartz. Second, the fines are associated with a high irreducible water saturation, which is present as a continuous phase and therefore raises the reservoir conductivity still further. The latter causative factor is more dominant than the previous. However, it is important that the water saturation first be evaluated correctly before it is apportioned into immobile and free-fluid components.
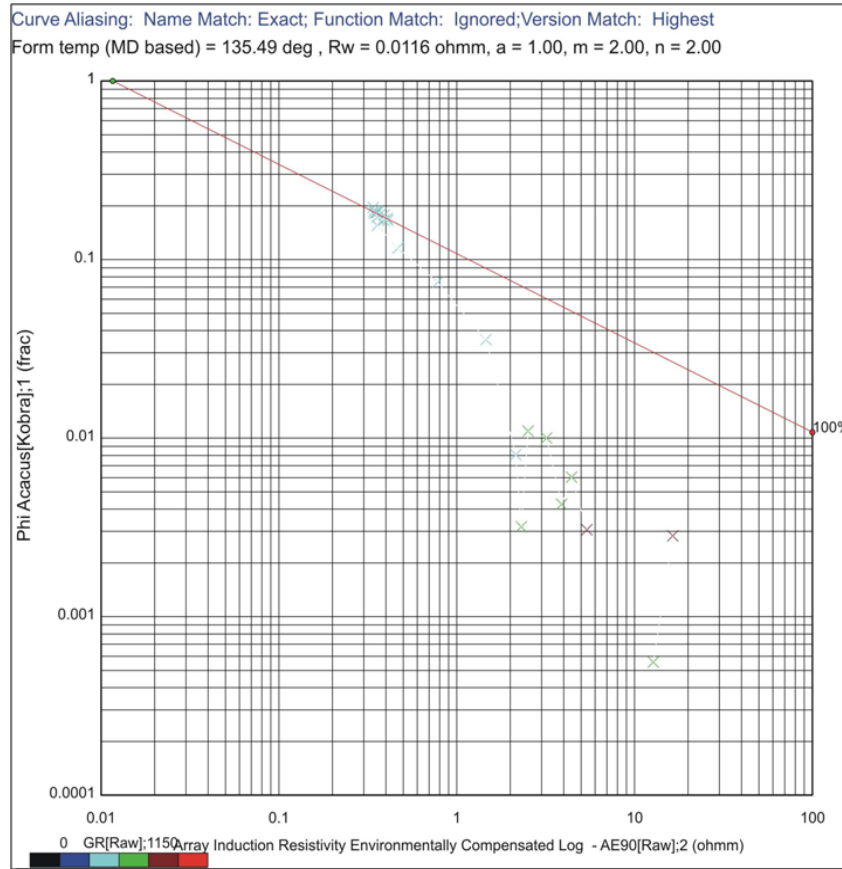
Figure 6. Water resistivity determination by Pickett plot in Acacus reservoir

The first stage is to observed that shaly-sand showed that the silt fraction was principally quartz with only minor amounts of dolomite and siderite. The second stage is to evaluate the free-fluid fraction of the pore space. The direct evaluation of free fluid, which equates to movable hydrocarbons under conditions of irreducible water saturation, is possible through magnetic resonance logging (Van de Weerd *et al.*, 1994; Busch *et al.*, 1987; Quirein *et al.*, 1986; Hedberg *et al.*, 1993; Howard, 1998; Lafargue *et al.*, 1988; Langhi *et al.*, 2010; Laubach 1988; Leythaeuser *et al.*, 1989; Leythaeuser *et al.*, 2000). This last application is expected to grow in the future as the capabilities and limitations of the technique become established.

archie approach of hydrocarbon saturation

The Archie approach used to evaluate the reservoir hydrocarbon saturation by the next equation Sh = 1- Sw. With SW= $(F.RW/RT)^{1/2}$

Where RT is the deep resistivity of the fluid saturated rock, and RW is the water resistivity of the pore-filling in flashed zone. The factor $F = a^n/\Phi^m$

Capital m is cementation factor; Values for m are typically used to understand the connectivity of the pore space; low values are interpreted to indicate highly connected pore space (usually in high-porosity rocks), and high values are interpreted to indicate poorly connected pore space (usually in low-porosity rocks and vuggy carbonates). However, in Acacus reservoir with on moderately-poorly sorted, moderate to fairly well cement and a visual poor porosity sandstones indicate that m values may be lower than expected, with values decreasing as porosity decreases. The value of the porosity exponent is constant for a given sample and is generally closer to the Archie value of 2.0. Some investigators have specified the exponent's **m** and **n** to be equal and m = n = 2 and a = 1. Therefore, the intergranular porosity and microporosity contain different fluid phases will be identified by neutron, sonic and density. The factor $F = a^n/\Phi^m$ thus F= $1/\Phi^2$

If sw = 1 Does it hurt (sw) 2 = F.RW/RT = 1 Thus F =   RT/Rw. Does it hurt $1/\Phi^2$ = RT/Rw   thus RW = Φ^2 * RT.

It was concluded that the resistivity of water formation RW in the Acacus reservoir in flashed area will be
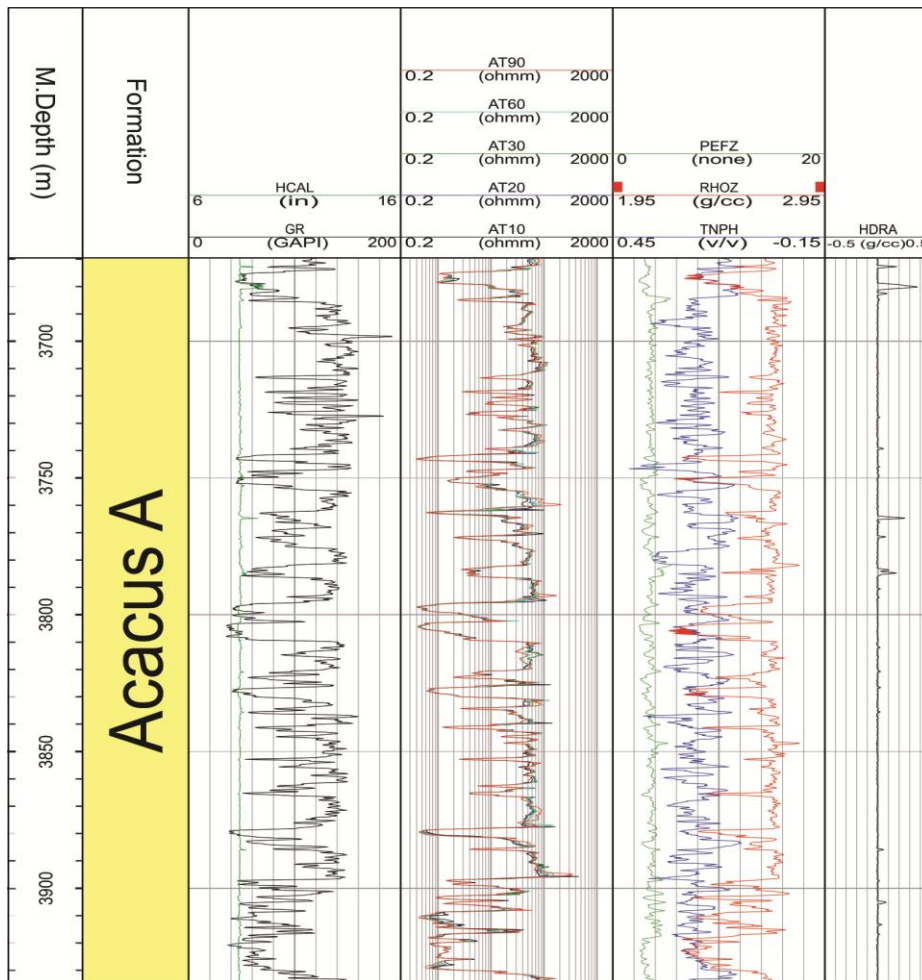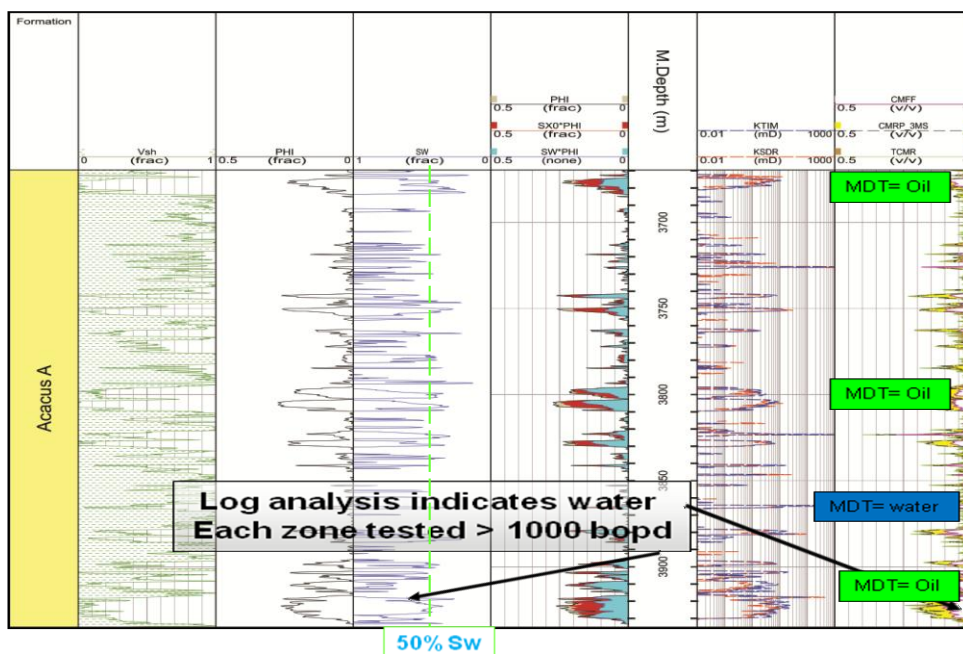
Figure 7. Log plot of Acacus reservoir

Figure 8. Log plot interpretation and MDT result of Acacus reservoir

determined by pickettplot (Φ^2 * RT) within and around the high water saturation layer, as indicated equal to 0.0116 ohm (Figure 6).

Petrophysical Evaluation

The Acacus reservoir shows a lower resistivity than other sediments of equal and comparable mineralogy. The spectral natural gamma ray log is particularly affected because of the limited intensity of the natural radiation emitted from the thin layers. The only way of reducing errors is a low logging speed, but this solution is not acceptable by the industry because of too long total measurement time. The conclusion is that in the selection of the optimum log data set for such rocks, Potassium K, Uranium U and Thorium Th will have low priority contrary to the neutron tool data, as stronger radiation is available from the neutron source. This phenomenon can be used to identify reservoir rocks on wireline logs and estimate a clay volume in the reservoir
layers without of differente distribution of Potassium, Uranium and Thorium minerals percentage between clay and sandstone facies (figure 7).

The resistivity of the washed zone RXo is necessary to compare it with the resistivity of the lateral no washed zone Rt and to estimate the free water and hydrocarbons volume. Sh = (1 - SW) and Shr = (1 - SXo): Sh represents the saturation of hydrocarbons; Shr the residual saturation in hydrocarbon in washed zone. The free volume of hydrocarbon is equal in Ø (Sh-Shr) =Ø(SXo-SW). Thus we notice that the volume of free hydrocarbon at the level of the well is similar in the layers where we have a great quantity of combined magnetic free fluid (CMFF) represented in the figure below (figure 8).

NUCLEAR MAGNETIC RESONANCE (NMR) STUDY AND ANALYSIS OF RESULTS

Proton nuclear magnetic resonance (NMR) has emerged as a rapid, nondestructive, and noninvasive measurement technique for field applications. In the petroleum industry, subsurface borehole probes designed to measure the relaxation of the proton magnetization in deep oil field reservoirs are widely used to understand reservoir formation petrophysical properties such as pore size, free fluid percentage and fluid types. The outcome of this research establishes the utility of proton NMR measurements in near-surface environmental applications for elucidating saturation properties in unconsolidated porous media, and for detecting the signature of water from free fluid percentage. The information obtained with these tools can provide means to monitor the environmental influences such as pore-size distributions.

The Irreducible water-saturation estimates from NMR-based pore-size distributions. In this study, we look at the relaxation time distributions extracted from downhole NMR measurements to determine pore geometry and volumetrics within a reservoir. This understanding leads to a better overall unconventional reservoir characterization. The CMR3ms used to estimate relaxation time of clay bound water we look at the CMR3ms extracted from downhole measurements to determine irreducible fluid and shale volume within a reservoir. When we have a high clay volume the quantity of free fluid and interstitials fluid volume decrease; the CMR estimates only the clay bound water with the relaxation time distributions lower than 3ms. This understanding leads to a good estimation of free fluid in an unconventional reservoir. The TCMR estimate the all quantity of free fluid in matrix, irreducible and clay bound water (figure 8).

The first requirement is to classify the reservoir as an Archie reservoir. Direct interpretation of low-resistivity pay zones has often involved variations on the classical clean-sand and shaly-sand procedures. The layers have a high water saturation prove oil in MDT test. These later layers oil bearing show a great quantity of free fluid estimated by CMR. Additionally, the NMR logs provide important information that enhances the description of low-resistivity pay (figure 8)

Wireline formation tester data: Modular Dynamic Data (MDT)

In Acacus A reservoir an MDT program was made, for a final total of 25 Pressure point measurements. We had 05 Dry Tests, and 12 lost seal.
We also got 07 Good Pretests with 2 of these which didn't stabilize. 4 LFA have been performed as the mobility certified it.
Formation Fluids have been collected water @ 3865, 5 m and oil @3675 m3910m; 3921m and 3800m in lower part of Acacus A formation (Table1).

DISCUSSION AND CONCLUSIONS

Archie measurements on a limited data set of Acacus sandstones demonstrate that resistivity depend strongly with deposits types, cementation mineralogy and fluid formation salinity Examination of NMR and MDT measurements indicate that the low-resistivity pay   is at least partially filled by hydrocarbon

Electric conductivity is the basic measurable physical parameter used to distinguish hydrocarbons and water and salty water in the pore space In the shale-sand formations there are two factors influencing the total rock conductivity,

Table 1. Petrophysical Parameters and Live Fluid Analysis (LFA) of MDT samples

Formation	Points MDT	VSHGR	SW	PHI ND	MDT and LFA
	3675.2	0	0.41	0.22	oil
	3678.6	0.33	0.39	0.13	dry
	3718.4	0.27	0.38	0.13	Lost seal
	3750.2	0.44	0.36	0.20	Lost seal
	3751.2	0.44	0.36	0.02	Lost seal
	3797	0.18	0.37	014	dry
	3800	0.14	0.40	014	oil
	3805	0.12	0.37	024	dry
Acacus A	38069	0.17	0.39	014	dry
	3809	0.17	0.39	014	Lost seal
	38229	0.12	0.46	014	dry
	3827	0.086	0.38	022	Lost seal
	38285	0.086	0.38	022	Lost seal
	3850	0.13	0.47	019	Not stabilize
	38655	0.80	0.27	017	water
	38793	0.28	0.43	014	Lost seal
	3910	0.33	0.49	01	oil
	3897	0.28	0.43	014	Lost seal
	39033	0.57	0.48	02	Not stabilize
	39055	0.57	0.48	020	Lost seal
	3910	0.52	0.33	022	oil
	3921	0.41	0.43	022	oil
	3924	0.41	0.43	022	Lost seal
	39268	0.92	0.45	018	Lost seal
Tannezuft	3970	0.11	0.25	014	Lost seal

represented by the ionic conductivity (presence of conductive mineral) of the pore space, and the conductivity created by the cation exchange phenomena on the surfaces of clay minerals, measurable by cation ionic exchange (CEC) The presence of conductive mineral (Chlorite Siderite) and cation ionic exchange are an important parameter influencing the Sw determination and explaining the presence of oil bearing in the layers identified by Archie as a water accumulation

Proton nuclear magnetic resonance (NMR) has emerged as a rapid, nondestructive, and noninvasive measurement technique for field applications in the petroleum industry, subsurface borehole probes designed to measure the relaxation of the proton magnetization in deep oil field reservoirs are widely used to infer reservoir formation petrophysical properties such as pore size, fluid volume, and fluid types.

The information obtained with these tools can provide the saturation in situ, such as pore-size distributions, mixed fluid saturations Using the same analytical technique-proton NMR measurements study of a single flow path at the micron scale with data obtained from the sum of the flow paths contained within a 15-cm zone in the formation outside a well borehole that penetrates a subsurface contaminant spiral This is important for computational models, because it reduces the uncertainties associated with scaling and offers the opportunity to determine at what scale of observation

heterogeneities in the porous medium are important for this reason we expect NMR to become an important tool in validating models of flow and transport in the vadose zone that are needed for designing remediation and long-term stewardship strategies Future studies, outside our research, could be directed to evaluate the utility of quantitative NMR T2- distribution measurements for assessing remediation efforts of subsurface contaminants Follow-on research could determine sensitivity, depth-of-investigation requirements needed to develop new field NMR instruments specifically designed for specific fine layers mixed facies and separation volume (oil from water) checking by tools applications designed to measure the relaxation time of the carbon magnetization in deep oil field sandstone reservoirs.

REFERENCES

Archieg E (1942). The electrical Resistivity log as an aid in determining some reservoir characteristics: Transactions of the American Institute of Mining, Metallurgical and Petroleum Engineers. 146:54–62.

Busch JM, Fortney WG, Berry LN (1987). Determination of lithology from well logs by statistical analysis: SPE formation evaluation: An official publication of the Society of Petroleum Engineers. 2(4):412–418.

Dardour AM, Boote DRD, Baird AW(2004). Stratigraphic controls on Palaeozoic petroleum systems, Ghadames Basin, Libya *J. Petroleum. Geol.* **27**:141–162

George SC, Volk H, Ahmed M(2007). Geochemical analysis techniques and geological applications of oil bearing fluid
inclusions, with some Australian case studies: J. Petrol. Sci. Eng. 57:119–138.

Grantham PJ, Wakefield L(1988).Variations in the sterane carbon number distributions of marine source rock derived crude oils
through geological time: Organic Geochemistry.12: 61–77

Gray I (1987). Troll, in A M Spencer, M T Thomas, A G Doré, P C Home, and R M Larsen, Geology of the Norwegian oil and gas fields: London, Graham and Trotman. 389–401

Hedberg SA, Knight RJ, Mackay A, Whittall KP (1993). The use of nuclear magnetic resonance for studying and detecting hydrocarbon contaminants in porous rocks: Water Resources Research, 29(4):1163–1170.

Howard JJ(1998). Quantitative estimates of free fluid quantity from proton NMR measurements: J. Magnetic Resonance Imaging. 16:529–533.

Lafargue E, Barker C(1988).Effect of water washing on crude oil composition: AAPG Bulletin, 72: 263–276.

Langhi L, Zhang YH, Gartrell A, Underschultz J, Dewhurst D (2010). Evaluating hydrocarbon trap integrity during fault reactivation using Geomechanical three dimensional modeling: An example from the Timor Sea, Australia: AAPG Bulletin. 94: 567–591.

Laubach SE(1988). subsurface fractures and their relationship to stress history in east Texas Basin sandstone: Tectonophysics, 156: 37–49.

Leverett MC (1941). Resistivity of brine-saturated sands in relation to pore geometry: AAPG Bulletin, 36:253–277.

Leythaeuser D, RÜCKHEIM J (1989). Eterogeneity of oil composition within a reservoir as a reflection of accumulation history: Geochimica and Cosmochimica Acta, 53: 2119–2123.

Leythaeuser D, Schwark L, Keuser CH (2000). Geological conditions and geochemical effects of secondary petroleum migration and accumulation: Marine and Petroleum Geology. 17: 857–859.

Quirein J, Kimminau S, Lavigne J, Singer J, Wendel F(1986). A coherent framework for developing and applying multiple formation evaluation models: 27th Annual Logging Symposium, Society of Petro physicists and Well Log Analysts

VAN DE Weerd A, Ware PLG (1994). A review of the east Algerian Sahara oil and gas province (Triassic, Ghadames and Illizi basins): First Break, 12(7): 363–373.

Zhang Z, Gonguet C, Rajani V, Roeterdink R (2008). Directional LWD resistivity tools and their business impacts: 49th Annual Logging Symposium, Society of Professional Well Log Analysts, Annual Convention Official Program, Vol 9, Pp. A2.