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Technically Recoverable Shale Oil and Shale Gas Resources:

Chad

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Introduction

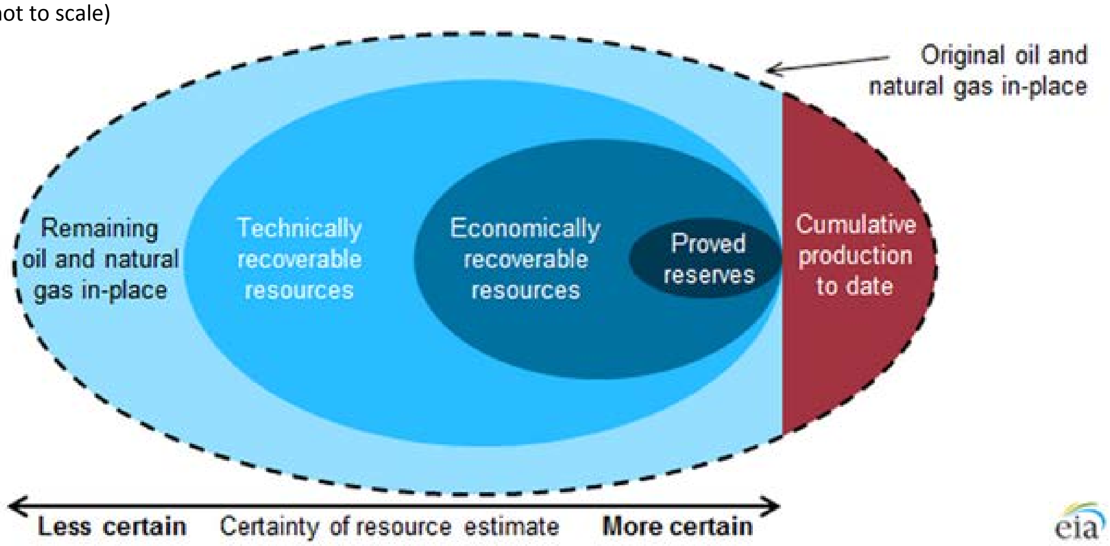
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically recoverable oil and natural gas resources. This chapter is a supplement to the 2013 EIA world shale report Technically Recoverable Shale Oil and Shale Gas Resources: An Assessment of 137 Shale Formations in 41 Countries Outside the United States.

Resource categories

When considering the market implications of abundant shale resources, it is important to distinguish between a technically recoverable resource, which is the focus of this supplement as in the 2013 report, and an economically recoverable resource. Technically recoverable resources represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Economically recoverable resources are resources that can be profitably produced under current market conditions. The economic recoverability of oil and gas resources depends on three factors: the costs of drilling and completing wells, the amount of oil or natural gas produced from an average well over its lifetime, and the prices received for oil and gas production. Recent experience with shale gas and tight oil in the United States and other countries suggests that economic recoverability can be significantly influenced by above-the-ground factors as well as by geology. Key positive above-the-ground advantages in the United States and Canada that may not apply in other locations include private ownership of subsurface rights that provide a strong incentive for development; availability of many independent operators and supporting contractors with critical expertise and suitable drilling rigs and, preexisting gathering and pipeline infrastructure; and the availability of water resources for use in hydraulic fracturing. See Figure 1.

Figure 1. Stylized representation of oil and natural gas resource categorizations

(not to scale)



Source: U.S. Energy Information Administration
Note: Resource categories are not drawn to scale relative to the actual size of each resource category. The graphic shown above is applicable only to oil and natural gas resources.

Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

For many purposes, oil and natural gas resources are usefully classified into four categories:

- Remaining oil and gas in-place (original oil and gas in-place minus cumulative production at a specific date)
- Technically recoverable resources
- Economically recoverable resources
- Proved reserves

The oil and natural gas volumes reported for each resource category are estimates based on a combination of facts and assumptions regarding the geophysical characteristics of the rocks, the fluids trapped within those rocks, the capability of extraction technologies, and the prices received and costs paid to produce oil and natural gas. The uncertainty in estimated volumes declines across the resource categories (see figure above) based on the relative mix of facts and assumptions used to create these resource estimates. Oil and gas in-place estimates are based on fewer facts and more assumptions, while proved reserves are based mostly on facts and fewer assumptions.

Remaining oil and natural gas in-place (original oil and gas in-place minus cumulative production). The volume of oil and natural gas within a formation before the start of production is the original oil and gas in-place. As oil and natural gas are produced, the volumes that remain trapped within the rocks are the remaining oil and gas in-place, which has the largest volume and is the most uncertain of the four resource categories.

Technically recoverable resources. The next largest volume resource category is technically recoverable resources, which includes all the oil and gas that can be produced based on current technology, industry practice, and geologic knowledge. As technology develops, as industry practices improve, and as the understanding of the geology increases, the estimated volumes of technically recoverable resources also expand.

The geophysical characteristics of the rock (e.g., resistance to fluid flow) and the physical properties of the hydrocarbons (e.g., viscosity) prevent oil and gas extraction technology from producing 100% of the original oil and gas in-place.

Economically recoverable resources. The portion of technically recoverable resources that can be profitably produced is called economically recoverable oil and gas resources. The volume of economically recoverable resources is determined by both oil and natural gas prices and by the capital and operating costs that would be incurred during production. As oil and gas prices increase or decrease, the volume of the economically recoverable resources increases or decreases, respectively. Similarly, increasing or decreasing capital and operating costs result in economically recoverable resource volumes shrinking or growing.

U.S. government agencies, including EIA, report estimates of technically recoverable resources (rather than economically recoverable resources) because any particular estimate of economically recoverable resources is tied to a specific set of prices and costs. This makes it difficult to compare estimates made by other parties using different price and cost assumptions. Also, because prices and costs can change over relatively short periods, an estimate of economically recoverable resources that is based on the prevailing prices and costs at a particular time can quickly become obsolete.

Proved reserves. The most certain oil and gas resource category, but with the smallest volume, is proved oil and gas reserves. Proved reserves are volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved reserves generally increase when new production wells are drilled and decrease when existing wells are produced. Like economically recoverable resources, proved reserves shrink or grow as prices and costs change. The U.S. Securities and Exchange Commission regulates the reporting of company financial assets, including those proved oil and gas reserve assets reported by public oil and gas companies.

Each year EIA updates its report of proved U.S. oil and natural gas reserves and its estimates of unproved technically recoverable resources for shale gas, tight gas, and tight oil resources. These reserve and resource estimates are used in developing EIA's Annual Energy Outlook projections for oil and natural gas production.

- Proved oil and gas reserves are reported in EIA’s U.S. Crude Oil and Natural Gas Proved Reserves.
- Unproved technically recoverable oil and gas resource estimates are reported in EIA’s Assumptions report of the Annual Energy Outlook. Unproved technically recoverable oil and gas resources equal total technically recoverable resources minus the proved oil and gas reserves.

Over time, oil and natural gas resource volumes are reclassified, going from one resource category into another category, as production technology develops and markets evolve.

Additional information regarding oil and natural gas resource categorization is available from the Society of Petroleum Engineers and the United Nations.

Methodology

The shale formations assessed in this supplement as in the previous report were selected for a combination of factors that included the availability of data, country-level natural gas import dependence, observed large shale formations, and observations of activities by companies and governments directed at shale resource development. Shale formations were excluded from the analysis if one of the following conditions is true: (1) the geophysical characteristics of the shale formation are unknown; (2) the average total carbon content is less than 2 percent; (3) the vertical depth is less than 1,000 meters (3,300 feet) or greater than 5,000 meters (16,500 feet), or (4) relatively large undeveloped oil or natural gas resources.

The consultant relied on publicly available data from technical literature and studies on each of the selected international shale gas formations to first provide an estimate of the “risked oil and natural gas in-place,” and then to estimate the unproved technically recoverable oil and natural gas resource for that shale formation. This methodology is intended to make the best use of sometimes scant data in order to perform initial assessments of this type.

The risked oil and natural gas in-place estimates are derived by first estimating the volume of in-place resources for a prospective formation within a basin, and then factoring in the formation’s success factor and recovery factor. The success factor represents the probability that a portion of the formation is expected to have attractive oil and natural gas flow rates.   The recovery factor takes into consideration the capability of current technology to produce oil and natural gas from formations with similar geophysical characteristics. Foreign shale oil recovery rates are developed by matching a shale formation’s geophysical characteristics to U.S. shale oil analogs. The resulting estimate is referred to as both the risked oil and natural gas in-place and the technically recoverable resource. The specific tasks carried out to implement the assessment include:

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.
2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*[1] and *adsorbed gas*[2] that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.[3] For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources[4] represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

Based on U.S. shale production experience, the recovery factors used in this supplement as in the previous report for shale gas generally ranged from 20 percent to 30 percent, with values as low as 15 percent and as high as 35 percent being applied in exceptional cases. Because of oil's viscosity and capillary forces, oil does not flow through rock fractures as easily as natural gas. Consequently, the recovery factors for shale oil are typically lower than they are for shale gas, ranging from 3 percent to 7 percent of the oil in-place with exceptional cases being as high as 10 percent or as low as 1 percent. The consultant selected the recovery factor based on U.S. shale production recovery rates, given a range of factors including mineralogy, geologic complexity, and a number of other factors that affect the response of the geologic formation to the application of best practice shale gas recovery technology. Because most shale oil and shale gas wells are only a few years old, there is still considerable uncertainty as to the expected life of U.S. shale wells and their ultimate recovery. The recovery rates used in this analysis are based on an extrapolation of shale well production over 30 years. Because a shale's geophysical characteristics vary significantly throughout the formation and analog matching is never exact, a shale formation's resource potential cannot be fully determined until extensive well production tests are conducted across the formation.

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[1] Free gas is natural gas that is trapped in the pore spaces of the shale. Free gas can be the dominant source of natural gas for the deeper shales.

[2] Adsorbed gas is natural gas that adheres to the surface of the shale, primarily the organic matter of the shale, due to the forces of the chemical bonds in both the substrate and the natural gas that cause them to attract. Adsorbed gas can be the dominant source of natural gas for the shallower and higher organically rich shales.

[3] The recovery factor pertains to percent of the original oil or natural gas in-place that is produced over the life of a production well.

[4] Referred to as risked recoverable resources in the consultant report.

Key exclusions

In addition to the key distinction between technically recoverable resources and economically recoverable resources that has been already discussed at some length, there are a number of additional factors outside of the scope of this report that must be considered in using its findings as a basis for projections of future production. In addition, several other exclusions were made for this supplement as in the previous report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

Some of the key exclusions for this supplement as in the previous report include:

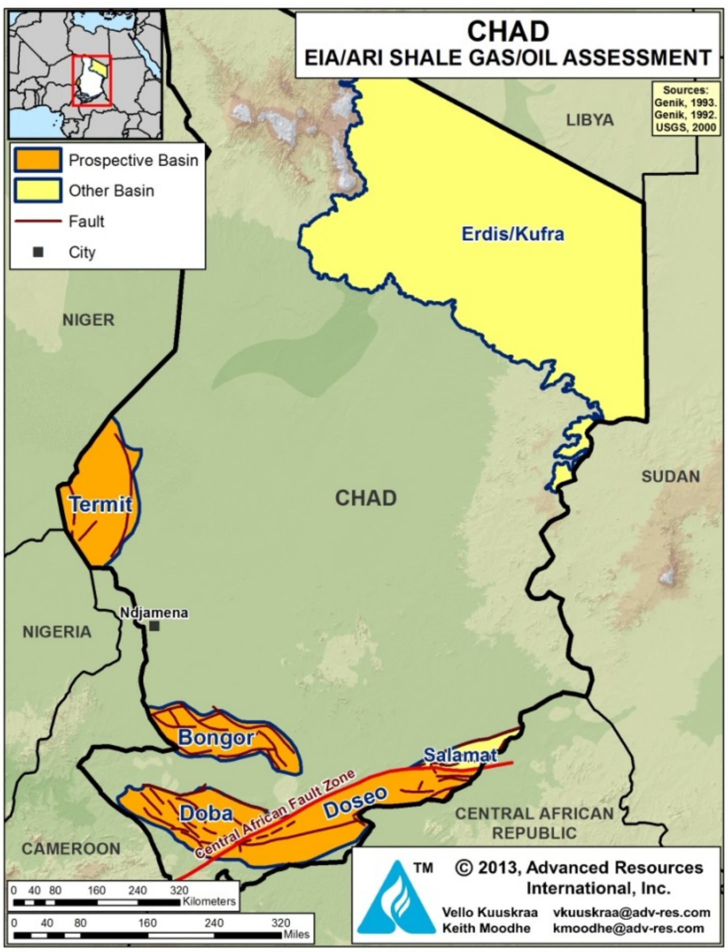
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas resources that may exist within these countries were also excluded from the assessment.
3. **Assessed formations without a resource estimate**, which resulted when data were judged to be inadequate to provide a useful estimate. Including additional shale formations would likely increase the estimated resource.
4. **Countries outside the scope of the report**, the inclusion of which would likely add to estimated resources in shale formations. It is acknowledged that potentially productive shales exist in most of the countries in the Middle East and the Caspian region, including those holding substantial non-shale oil and natural gas resources.
5. **Offshore portions of assessed shale oil** and shale gas formations were excluded, as were shale oil and shale gas formations situated entirely offshore.

CHAD

SUMMARY

Chad has shale gas and shale oil potential in three distinct petroleum provinces - - in the intra-cratonic Termit Basin (part of the larger Chad Basin) in the west; in four Central African Rift System basins of Bongor, Doba, Doseo and Salamat in the south, and in the Erdis Basin (called the Kufra Basin in Libya) in the north (Figure 1). This Chapter discusses all six of these basins, but, due to limitation in data, the resource assessment quantitatively addresses only four of these basins - - Termit, Bongor, Doba and Doseo.

Figure 1. Chad's Shale Gas and Shale Oil Basins



Source: ARI, 2013.

We estimate that the four main hydrocarbon basins of Chad contain 393 billion barrels of risked in-place shale oil, with 16.2 billion barrels as the risked, technically recoverable resource, Table 1. In addition, we estimate that these four basins contain 439 Tcf of risked, in-place wet and associated shale gas, with 44 Tcf as the risked, technically recoverable resource, Table 2.

Table 1. Shale Oil Reservoir Properties and Resources of Chad

			Termit				Bongor	Doba	Doseo
Basic Data	Basin/Gross Area		(44,000 mi^2)				(8,200 mi^2)	(9,100 mi^2)	(13,600 mi^2)
Basic Data	Shale Formation		L. Cretaceous		U. Cretaceous		L. Cretaceous	L. Cretaceous	L. Cretaceous
Basic Data	Geologic Age		L. Cretaceous		U. Cretaceous		L. Cretaceous	L. Cretaceous	L. Cretaceous
Basic Data	Depositional Environment		Lacustrine		Marine		Lacustrine	Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		1,990	950	5,580	3,840	4,640	3,450	5,530
Physical Extent	Thickness (ft)	Organically Rich	660	660	500	500	660	660	660
Physical Extent	Thickness (ft)	Net	400	400	150	150	400	330	460
Physical Extent	Depth (ft)	Interval	8,200 - 13,000	13,000 - 16,400	8,200 - 13,000	13,000 - 16,400	8,200 - 16,400	8,200 - 16,400	7,500 - 16,400
Physical Extent	Depth (ft)	Average	10,500	14,500	10,500	14,500	12,000	12,000	12,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal	Normal
Reservoir Properties	Average TOC (wt. %)		2.5%	2.5%	2.0%	2.0%	2.5%	2.0%	3.0%
Reservoir Properties	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	0.85%	0.85%	0.85%
Reservoir Properties	Clay Content		Medium	Medium	Low/Medium	Low/Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Oil	Oil	Oil
Resource	OIP Concentration (MMbbl/mi^2)		58.4	13.4	21.9	5.0	56.0	46.2	64.4
Resource	Risked OIP (B bbl)		27.9	3.1	36.7	5.8	62.3	79.6	178.0
Resource	Risked Recoverable (B bbl)		1.12	0.12	1.83	0.29	2.49	3.19	7.12

Source: ARI, 2013.

Table 2. Shale Gas Reservoir Properties and Resources of Chad

			Termit				Bongor	Doba	Doseo
Basic Data	Basin/Gross Area		(44,000 mi^2)				(8,200 mi^2)	(9,100 mi^2)	(13,600 mi^2)
Basic Data	Shale Formation		L. Cretaceous		U. Cretaceous		L. Cretaceous	L. Cretaceous	L. Cretaceous
Basic Data	Geologic Age		L. Cretaceous		U. Cretaceous		L. Cretaceous	L. Cretaceous	L. Cretaceous
Basic Data	Depositional Environment		Lacustrine		Marine		Lacustrine	Lacustrine	Lacustrine
Physical Extent	Prospective Area (mi^2)		1,990	950	5,580	3,840	4,640	3,450	5,530
Physical Extent	Thickness (ft)	Organically Rich	660	660	500	500	660	660	660
Physical Extent	Thickness (ft)	Net	400	400	150	150	400	330	460
Physical Extent	Depth (ft)	Interval	8,200 - 13,000	13,000 - 16,400	8,200 - 13,000	13,000 - 16,400	8,200 - 16,400	8,200 - 16,400	7,500 - 16,400
Physical Extent	Depth (ft)	Average	10,500	14,500	10,500	14,500	12,000	12,000	12,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal	Normal
Reservoir Properties	Average TOC (wt. %)		2.5%	2.5%	2.0%	2.0%	2.5%	2.0%	3.0%
Reservoir Properties	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	0.85%	0.85%	0.85%
Reservoir Properties	Clay Content		Medium	Medium	Low/Medium	Low/Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Assoc. Gas	Wet Gas	Assoc. Gas	Assoc. Gas	Assoc. Gas
Resource	GIP Concentration (Bcf/mi^2)		50.7	133.8	19.0	47.4	52.0	42.9	59.8
Resource	Risked GIP (Tcf)		24.2	30.5	31.8	54.6	57.9	74.0	165.4
Resource	Risked Recoverable (Tcf)		1.9	4.6	3.2	10.9	4.6	5.9	13.2

Source: ARI, 2013.

INTRODUCTION

The shale resource assessment for Chad provides a useful first step toward understanding the larger shale gas and shale oil potential of the West and Central African Rift System. Chad contains five of these Cretaceous- and Tertiary-age rift system basins, with Niger, Nigeria and the Central African Republic holding the remainder.[*] These rift basins were formed by the extension and subsequent subsidence of Central African crustal blocks during the breakup of Gondwana in Early Cretaceous time, followed by reactivated plate movements during the Early Tertiary. As these rift basins expanded, they received massive volumes of shale and clastic sediments that are the targets of oil and gas exploration in Chad.

Chad, with current annual oil production of 104,000 barrels per day and remaining proved oil reserves of 1.5 billion barrels, is an important, though modest, petroleum producer located in Central Africa. Exploration for oil in Chad first began in 1969 by ConocoPhillips, resulting in discoveries in 1975 in the Lake Chad (Termit) Basin and the Doba Basin. With outbreak of a civil war in 1979, exploration came to a halt. Subsequently, a consortium of petroleum companies acquired a long-term concession to develop the oil fields in the Doba Basin and to transport the oil for export.

After several transactions, ExxonMobil, Chevron and Petronas became members of the Consortium, built the $2.4 billion (U.S.), 665-mile, 225,000 B/D capacity Chad-Cameroon oil export pipeline, and initiated oil production in 2003. CNPC entered Chad in late 2003, purchasing the large exploration Block H from the Swiss company Cliveden. Chad established a national oil company SHT in 2006. Following the implementation of a Model Production Sharing Contract in 2010, Chad/SHT began awarding exploration concession areas and contracts to a new set of small, aggressive E&P companies such as Griffiths Energy (now Carcal), EHRC Energy, United Hydrocarbons Int., and Simba Energy.

[*] Some authors have classified the Termit (Chad) Basin as an intra-cratonic, rift-influenced basin, with a tectonic history somewhat different than Chad's other more classic rift basins.

With the completion of the Chad-Cameroon pipeline, oil production increased rapidly reaching a peak of 210,000 barrels per day in 2004.[1] Since then oil production has declined steadily as the initial set of oil fields, primarily in the Doba Basin, have steadily matured. Maintaining oil production is important for Chad, as oil accounts for a significant portion (27%) of Chad's GDP and provides the majority (63%) of government revenues. With the continuing decline in oil production, the Chad government stated that its GDP growth would fall in half in 2013, to 4.5% compared to 8.9% in 2012.

A significant shale oil (and shale gas) resource exists in Chad that could help reverse the decline in oil production, as further discussed in this report. In addition, the new Model Productive Sharing Contract provides reasonable terms for international companies to pursue this shale resource. Shale exploration would be enhanced if a market for natural gas would be developed in Chad, mostly for gas-fired electric power, or if the produced gas could be transported for conversion to LNG for export.

1. TERMIT BASIN

1.1 Introduction and Geologic Setting

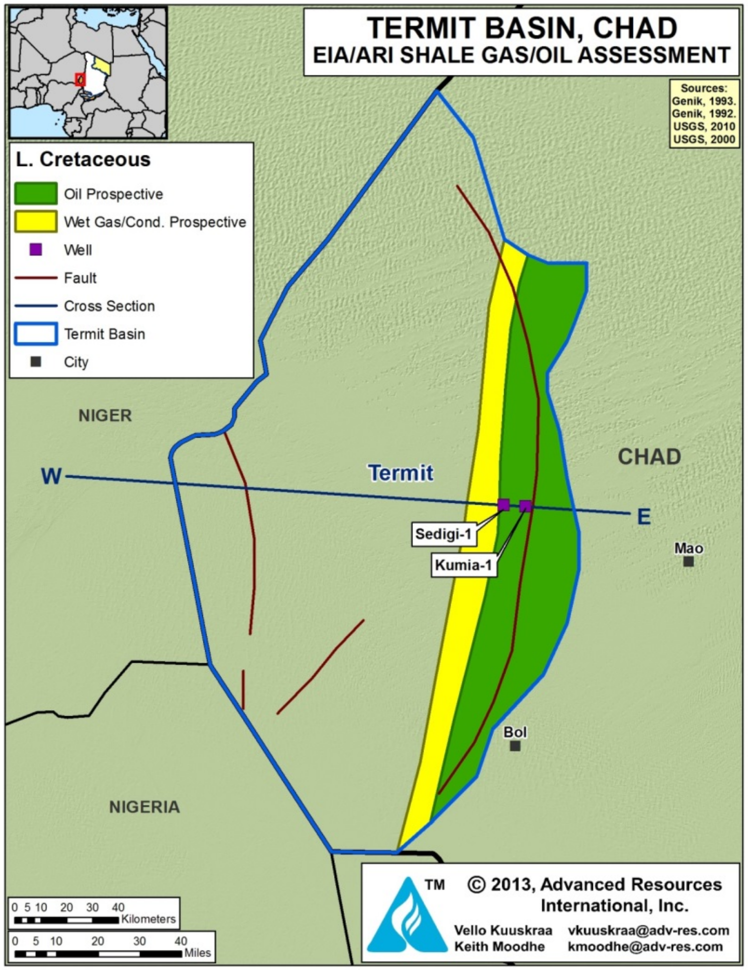
Approximately 11,400 mi^2 of the much larger (44,000 mi^2) Central and Western Africa Termit Basin exists within Chad. The northeastern, southwestern and eastern boundaries of the Termit Basin in Chad are defined by Cretaceous and Tertiary extensional rifting during the separation of South America and Africa; its western boundary is defined by Chad's borders with Niger and Nigeria.

The outline of the Termit Basin and its Lower and Upper Cretaceous Formation prospective areas are shown in Figures 2 and 3. The Termit Basin's Lower Cretaceous shale has an oil prospective area along the eastern boundary of the basin and a gas prospective area toward the center of the basin. The Termit Basin's Upper Cretaceous shale has oil prospective areas on the eastern and western boundaries of the basin and a gas prospective area in the deeper basin center.

The Termit (Chad) Basin's massive volumes of Cretaceous through Tertiary sediments are deposited directly on the Pre-Cambrian basement, as shown by the generalized stratigraphic column, Figure 4.[2] The sediment thickness in the Termit Basin ranges from about 2 km along the basin edge to over 10 km in the center of the basin, Figure 5.[2] Two cross-sections across the southern portion of the Termit Basin in Chad illustrate the extensive Upper and Lower Cretaceous sediments in this basin.

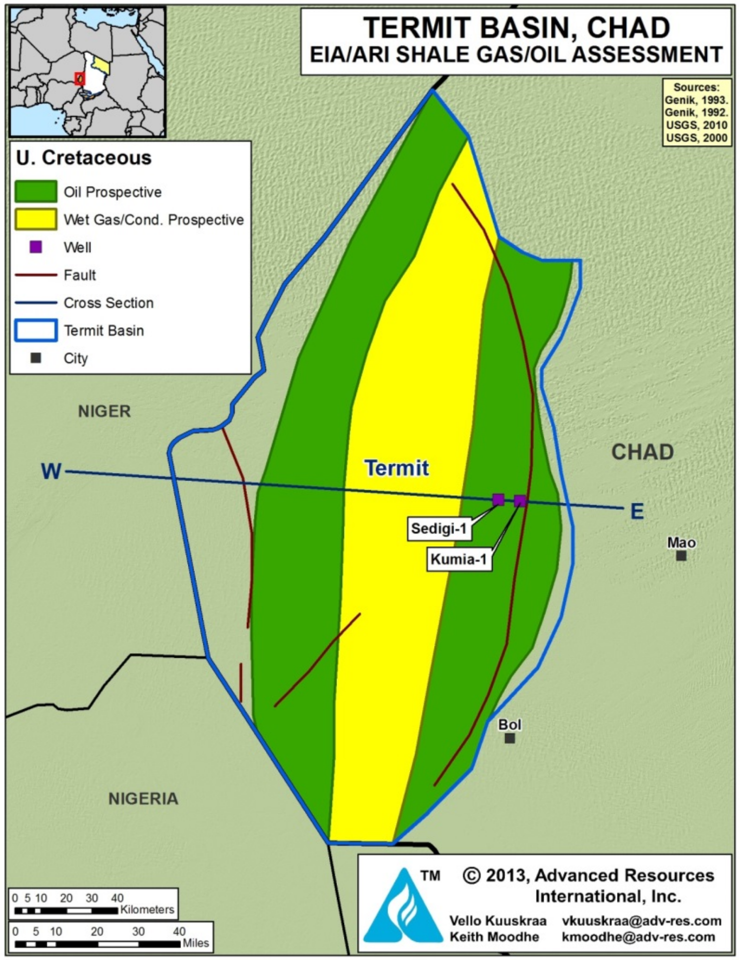
- Figure 6,[3,4] an east-to-west cross-section (see Figure 3 for cross-section location), shows the nearly 10,000 km thick Paleogene through Lower Cretaceous sediment fill in the central portion of the Termit Basin in Chad and eastern Niger.
- Figure 7,[1] a northeast-to-southwest cross-section, extending from Chad to Nigeria, further illustrates the extensive Cretaceous and younger sediment deposited directly on the Pre-Cambrian. Figure 7 also notes the key exploration wells - - Kanem-1, Nerga-1, Larco-1, Sedigi-1, Kumia-1 and Kosah-1 - - drilled into the deeper portions of the Termit Basin in Chad.

Figure 2. Termit Basin (Chad), Prospective Areas for Lower Cretaceous Shale



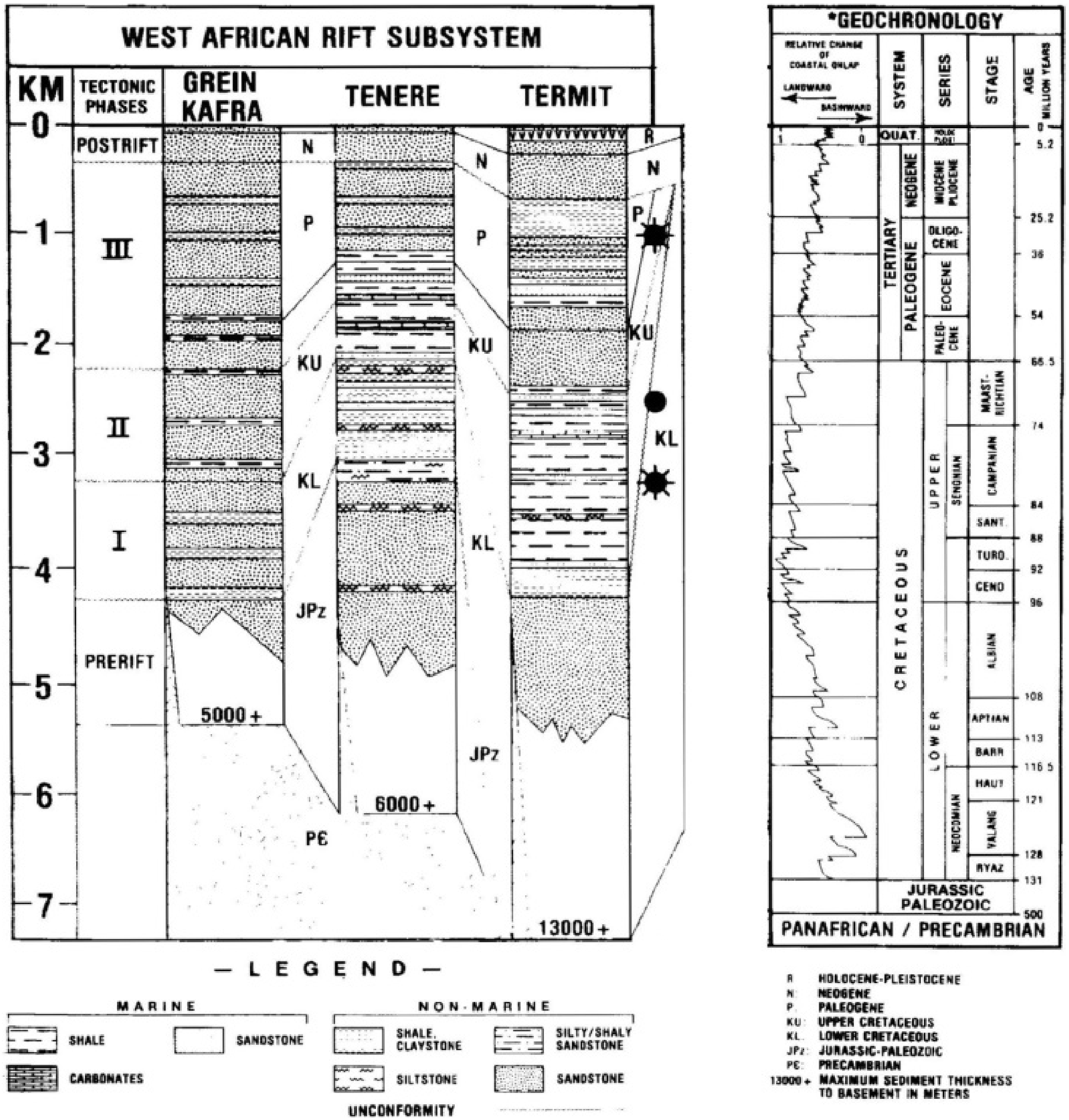
Source: ARI, 2013

Figure 3. Termit Basin (Chad), Prospective Areas for Upper Cretaceous Shale



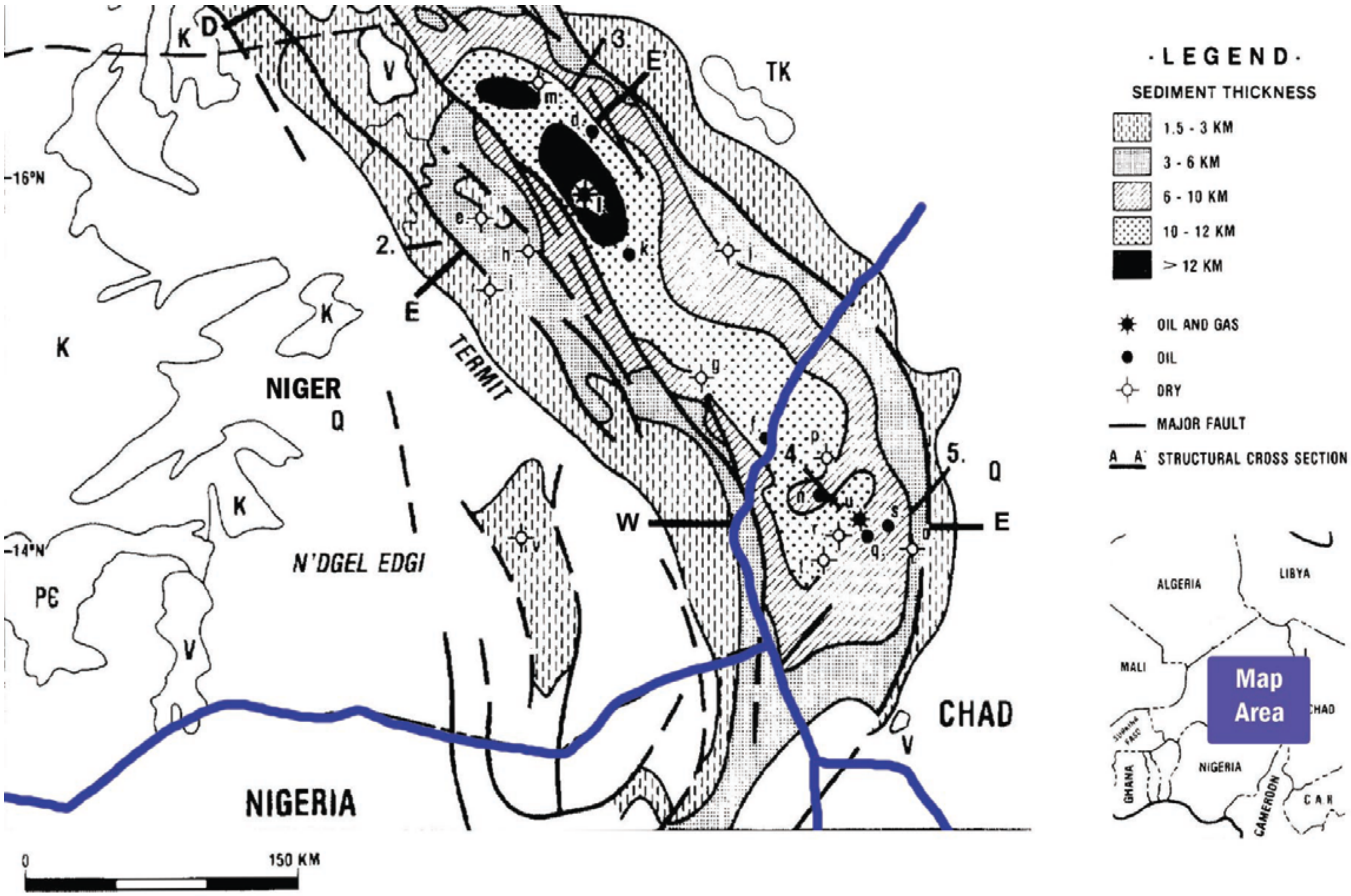
Source: ARI, 2013

Figure 4. Termit Basin Stratigraphic Column



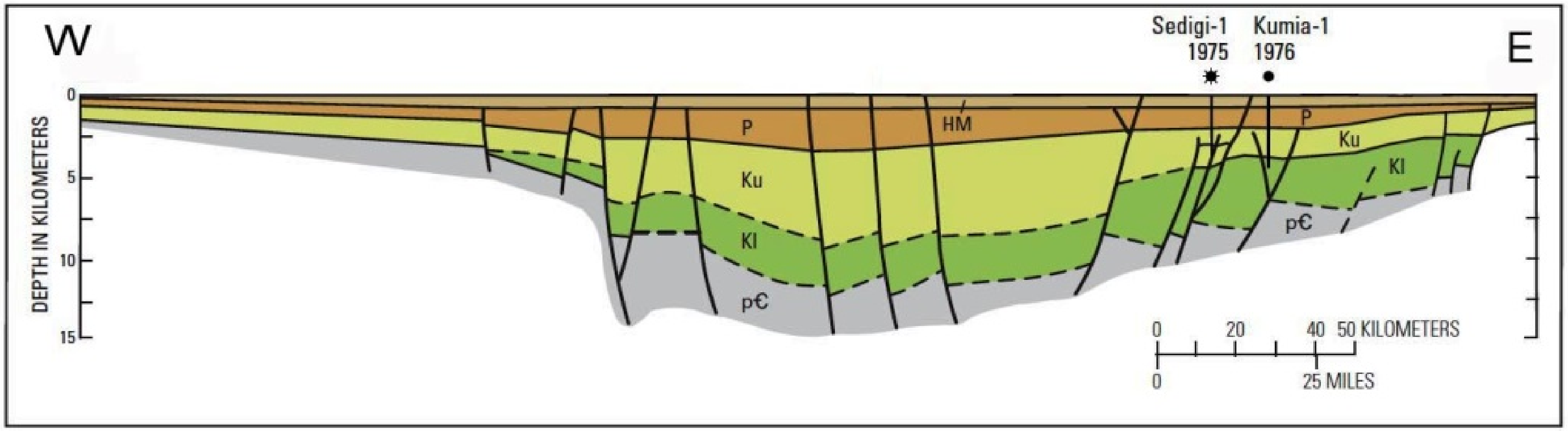
Source: Genik, 1993

Figure 5. Sediment Thickness, West Termit Basin, Niger/NW Chad



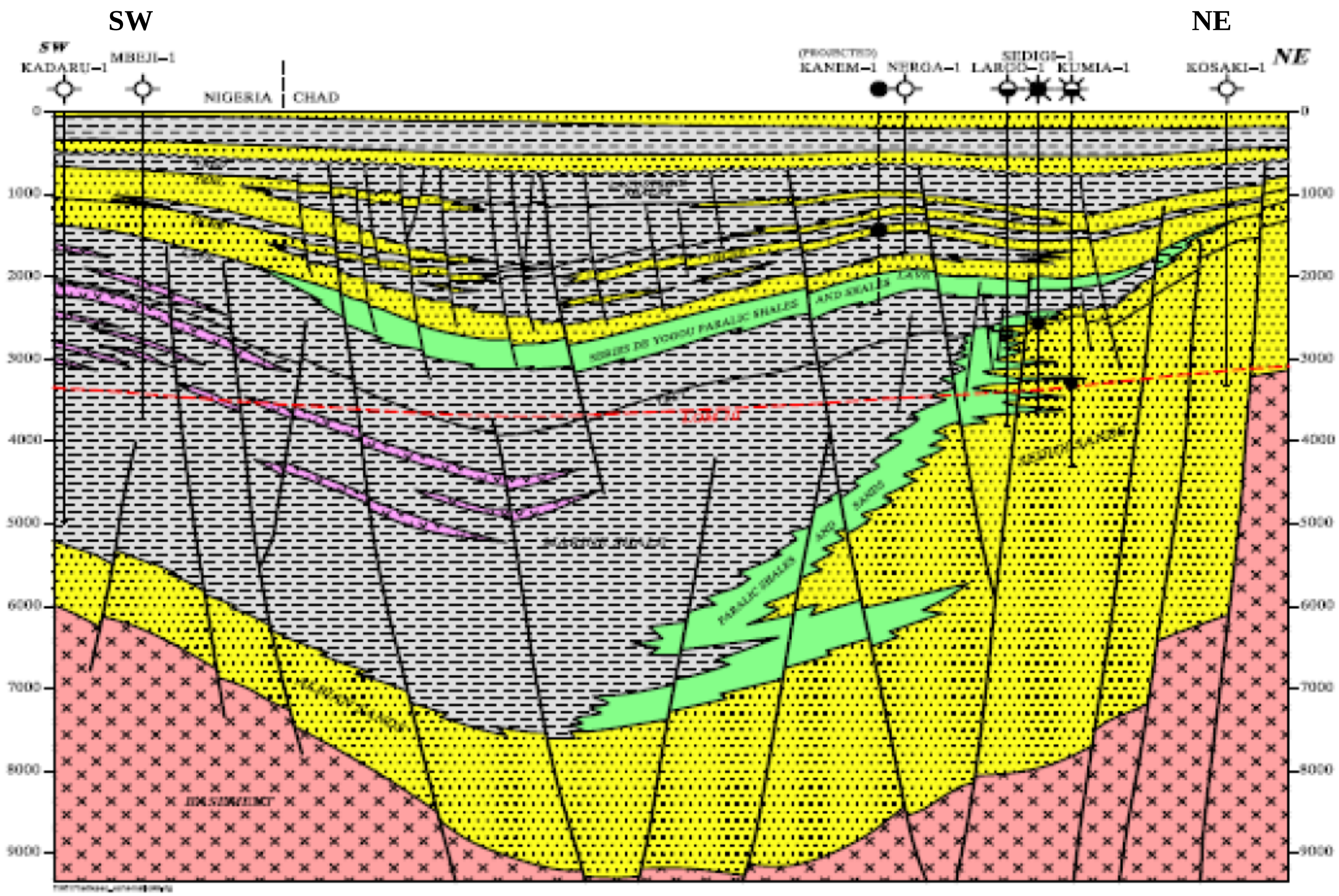
Source: Genik, 1993

Figure 6. Termit Basin West-to-East Cross-Section



Source: Modified after Genik (1992) and USGS (2010).
Schematic cross-section showing sedimentary fill of Termit Basin in Chad. Location of cross-section on Figure 4. Kl, Lower Cretaceous; Ku, Upper Cretaceous..

Figure 7. Termit Basin SW-to-NE Cross-Section



Source: United Hydrocarbon International Corp., 2013

Advanced Resources International, Inc.

The primary source rock shales in this basin are the Cretaceous lacustrine and marine deposits that have generated the commercial deposits of hydrocarbons in the shallower conventional oil fields discovered to date.

- Based on analog data from the Doba Basin to the east, the Lower Cretaceous shales in the Termit Basin are likely to hold the higher quality shale resource, with relatively thick 30 to 60 ft (10 to 20 m), high-TOC packages of shales distributed over a 660 ft (200 m) gross and 400 ft (160 m) net interval. The TOC of the Lower Cretaceous shales ranges from 2% to nearly 10%, with an average of 2.5%, Figure 8A.[2]
- The organic-rich segments of the Upper Cretaceous shales in Termit Basin are distributed as relatively thin 6 to 20 ft (2 to 10 m), moderate-TOC intervals within a 500 ft (150 m) gross and 150 ft (50 m) net interval. The TOC of the Upper Cretaceous shales ranges from less than 2% to 5%, Figure 8B.[2]

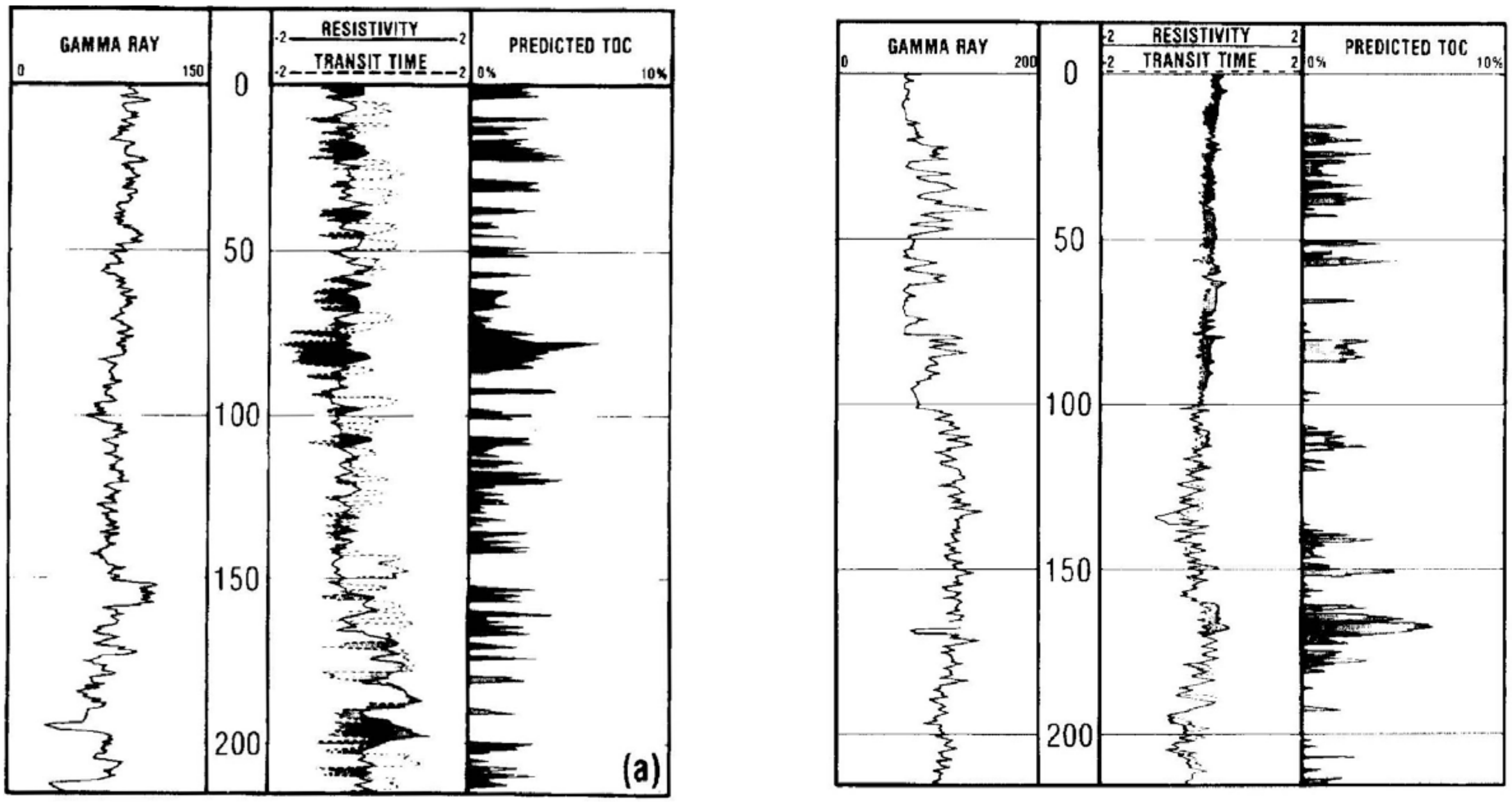
The organic matter in the Lower Cretaceous shales is of lacustrine origin, consisting primarily of Type III plant matter sourced kerogen. The organic matter in the Upper Cretaceous shales is of marine origin, consisting of both Type III and some Type II kerogen, Figure 9.[2]

The maturity of the shale source rocks in the Termit Basin is closely correlated with depth, with the oil generation window at 8,200 to 13,000 ft (2,500 to 4,000 m) and the wet gas window from 13,000 ft to below 16,400 ft (4,000 m to below 5,000 m). We have defined the oil and gas prospective areas of the basin using these depth related thermal maturity guidelines.

Figure 8. Relationship of Gamma Ray and Resistivity Log Curves for Doba and Termit Basins

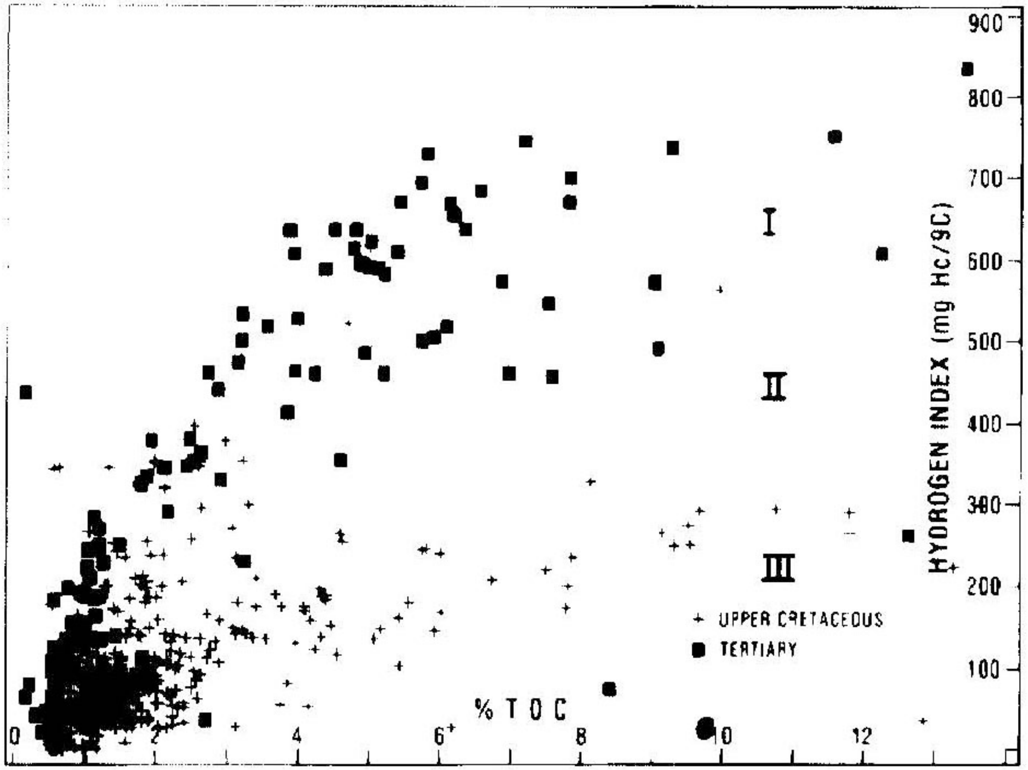
A. Lower Cretaceous Shale
Doba Basin

B. Upper Cretaceous Shale
Termit Basin



Source: Genik, 1993

Figure 9. Relationship of TOC and Hydrogen Index, Termit Basin



Source: Genik, 1993.
640 samples from selected wells in Termit Basin. All Cretaceous values and Tertiary values of HI < 600 are from marine shales; Tertiary values of HI > 600 are from lacustrine shales. Type III values predominate.

1.2 Reservoir Properties (Prospective Area)

1.2.1 Lower Cretaceous Shale

The depth of the oil prospective area (thermal maturity of 0.7% to 1.0% R_o) of the Lower Cretaceous shale in the Termit Basin of Chad ranges from 8,200 ft along the eastern basin boundary (top of the oil window) to 13,000 ft (base of the oil window), averaging 10,500 ft (see Figure 3). The organic-rich lacustrine shale has a net thickness of 400 ft within a gross interval of 660 ft and has an average TOC of 2.5%. We assume the reservoir pressure gradient to be normal.

The depth of the wet gas prospective area (thermal maturity of 1.0% to 1.3% Ro) of the Lower Cretaceous shale in the Termit Basin of Chad ranges from 13,000 ft, top of the wet gas window along the eastern portion of the basin, to 16,400 ft (5,000 m), the study depth cut-off criterion, toward the center of the basin, averaging 14,500 ft. The organic-rich shale has a net thickness of 400 ft within a gross interval of 660 ft and has an average TOC of 2.5%. Again we assume the reservoir pressure gradient to be normal.

The temperature gradient in the Termit Basin is about 1.4^{o}F per 100 ft. The gravity of the oil samples taken in the deeper Cretaceous Senonian-age interval of the Termit Basin in Chad ranged from 43^o to 54^o API, with a high, 2 Mcf/B, gas-oil ratio.

1.2.2 Upper Cretaceous Shale

The depth of the oil prospective area (thermal maturity of 0.7% to 1.0% Ro) of the Upper Cretaceous shale in the Termit Basin of Chad ranges from 8,200 ft (top of the oil window) in the eastern and western basin boundaries of the prospective area to 13,000 ft (base of the oil window) in the center of the basin, averaging 10,500 ft (see Figure 3). The organic-rich marine-paralic source shale has a net thickness of 150 ft within a gross interval of 500 ft and has an average TOC of 2%. We assume the reservoir pressure to be normal.

The depth of the gas prospective area (thermal maturity of 1.0% to 1.3% Ro) of the Upper Cretaceous shale in the Termit Basin of Chad ranges from 13,000 ft, top of the wet gas window, in the center of the basin to 16,400 ft (5,000 m), the study depth cut-off criterion, averaging 14,500 ft. The organic-rich shale has a net thickness of 150 ft within a gross interval of 500 ft and has an average TOC of 2%. We assume the reservoir pressure gradient to be normal.

1.3 Resource Assessment

1.3.1 Lower Cretaceous Shale. The Lower Cretaceous shale in the Chad portion of the Termit Basin has a 1,990-mi^2 area prospective for oil, with a resource concentration of 58 million barrels/mi^2 (plus associated gas). The wet gas and condensate prospective portion of the Lower Cretaceous shale covers an area of 950 mi^2 and has a resource concentration of 134 Bcf/mi^2 (plus condensate).

The risked resource in-place for the two Lower Cretaceous shale prospective areas is 31 billion barrels of shale oil/condensate and 55 Tcf of associated and wet gas. Of this, 1.2 billion barrels of oil/condensate and 7 Tcf of associated and wet gas are the risked, technically recoverable resources.

1.3.2 Upper Cretaceous Shale. The Upper Cretaceous shale, within its 5,580-mi^2 oil prospective area, has a resource concentration of 22 million barrels/mi^2 (plus associated gas). The wet gas and condensate prospective area of the Upper Cretaceous Shale covers an area of 3,840 mi^2 and has a resource concentration of 47 Bcf/mi^2 (plus condensate).

The risked resource in-place for the two prospective areas of the Upper Cretaceous shale is 43 billion barrels of shale oil/condensate and 86 Tcf of associated and wet gas. The risked, technically recoverable resources are estimated at 2.1 billion barrels of oil/condensate and 14 Tcf of wet and associated gas.

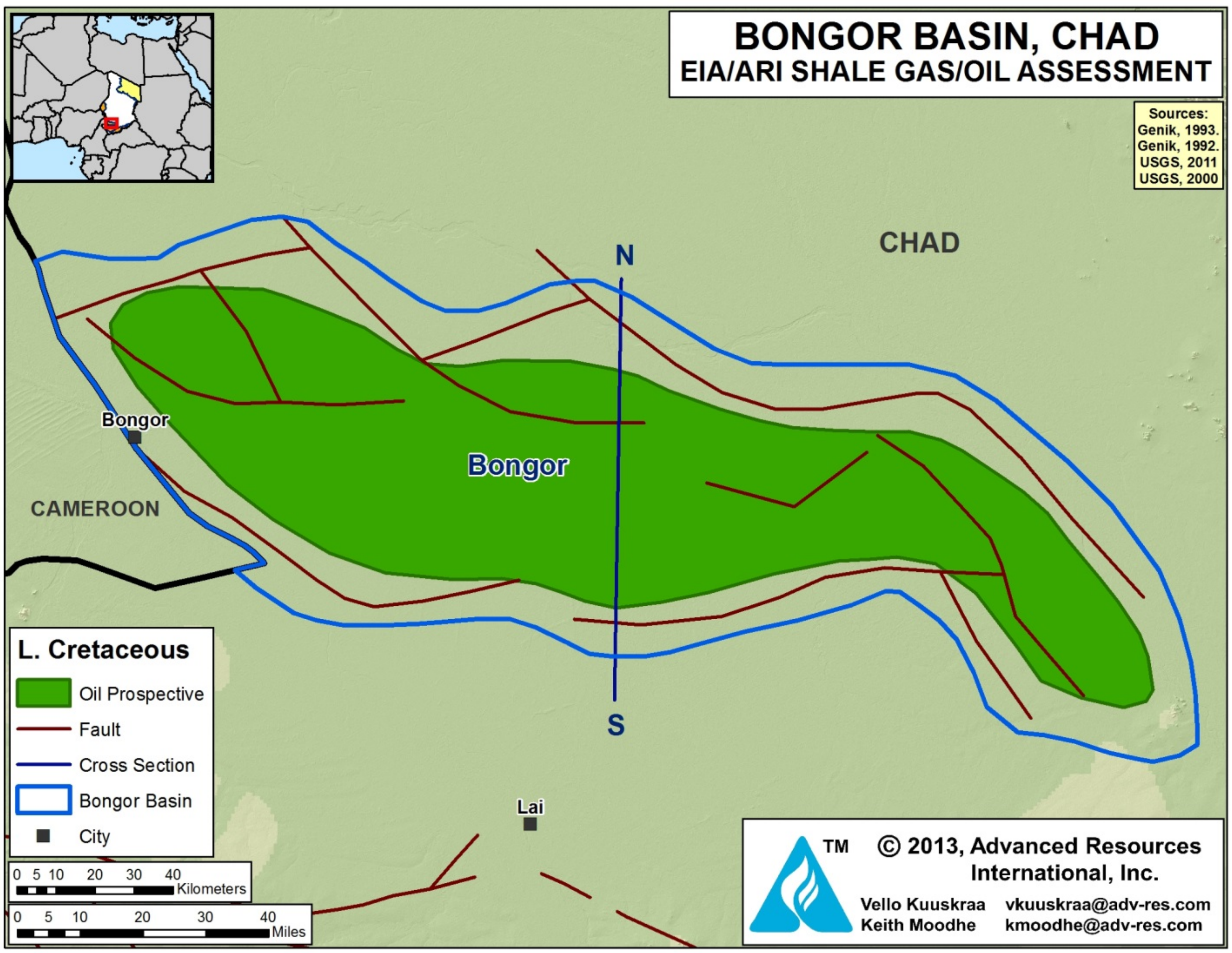
2. BONGOR BASIN

2.1 Introduction and Geologic Setting

The Bongor Basin, covering an area of 8,200 mi^2, is the northern most of the four Central African Rift System basins. The basin is bounded on the north, south, east and west by a series of deep-seated rift-influenced faults, Figure 10.

The Bongor Basin contains the producing Mimosa and Ronier oil fields operated by China National Petroleum Corp. (CNPC), producing from shallower horizons. Oil production from these two fields started in April, 2011. The produced light oil is transported via a 311-km pipeline (capacity of 20,000 B/D) to the Djarmaya refinery.

Figure 10. Bongor Basin Prospective Area for Lower Cretaceous Shale



Source: ARI 2013

The basin contains significant volumes of Lower Cretaceous sediments deposited directly on the Pre-Cambrian basin. Figure 11 provides a generalized stratigraphic column of the Bongor as well as the other three Central African Rift System basins, namely Doba, Doseo and Salamat.[2]

The Lower Cretaceous sediment thickness in the Bongor Basin ranges from about 2,000 m along the northern border of the basin to over 5,000 m along its southern border, as illustrated by the north-to-south cross-section, Figure 12.[3,5]

The Lower Cretaceous shales are predominantly Type III and Type I kerogen, with a TOC that ranges from 1% to over 5%. The thermal maturity of the Lower Cretaceous shale increases with depth, reaching the oil window at about 8,200 ft with the base of the oil window at 16,400 ft (the depth cut-off for the study), Figure 13.[2]

2.2 Reservoir Properties (Prospective Area)

The depth of the Lower Cretaceous shale oil prospective area of the Bongor Basin (thermal maturity range of 0.7% to 1.0% Ro) ranges from 8,200 ft along the northern basin boundary (top of the oil window) to 16,400 ft (depth limit of study) in the center of the basin and its southern boundary, averaging 12,000 ft, (see Figure 10).

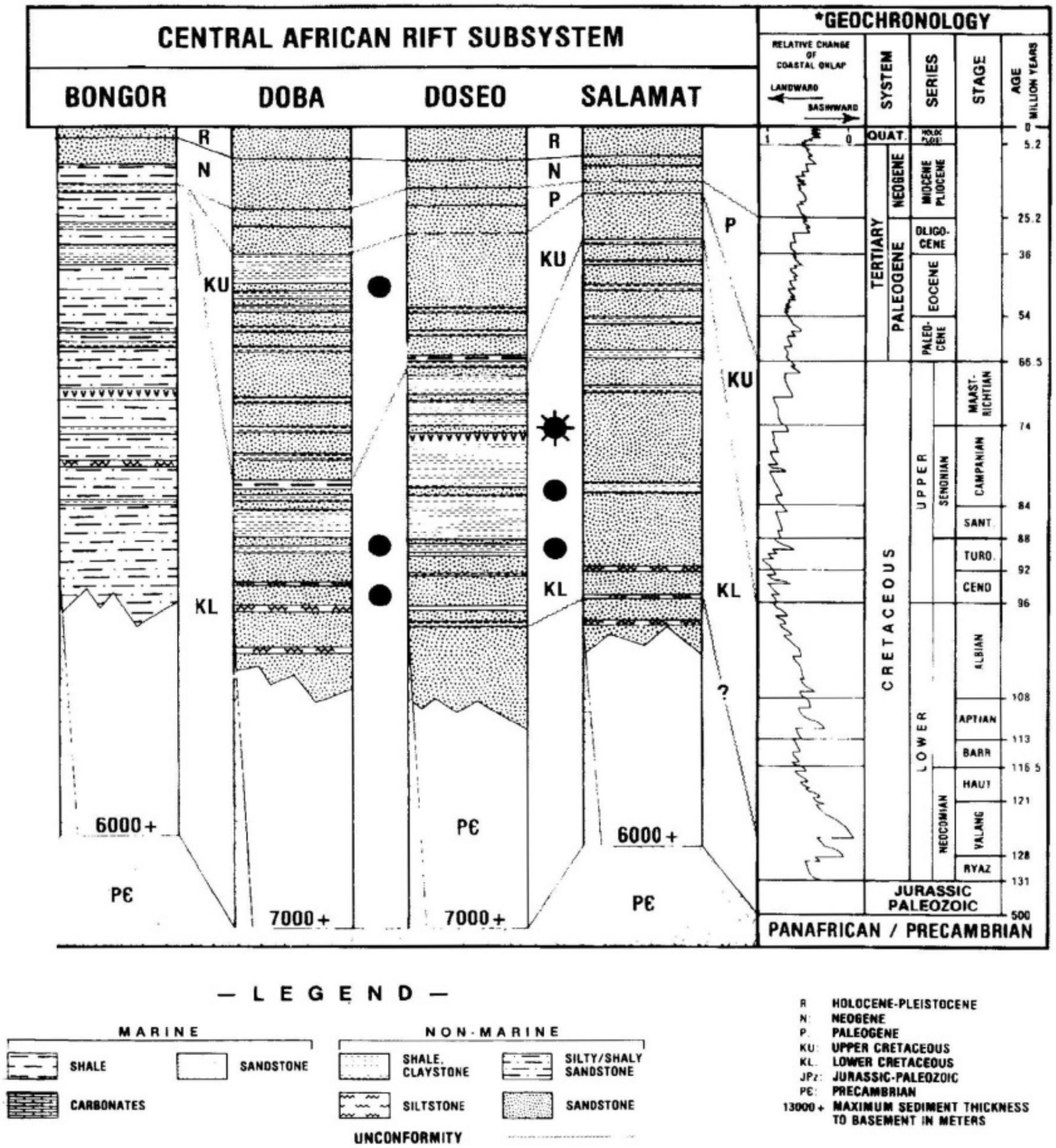
The organic-rich lacustrine shale has a net thickness of about 400 ft within a gross interval of 660 ft and has an average TOC of 2.5%, Figure 15.[2] The reservoir pressure gradient is assumed to be normal and the reservoir temperature gradient is about 1.5^{o}F/100 ft.

2.3 Resource Assessment

The Lower Cretaceous shale in the Bongor Basin has a 4,640-mi^2 area prospective for oil, with a resource concentration of 56 million barrels/mi^2 (plus associated gas).

The risked resource in-place for the Lower Cretaceous shale prospective area is 62 billion barrels of shale oil and 58 Tcf of associated gas. The risked, technically recoverable resources are 2.5 billion barrels of oil and 5 Tcf of associated gas.

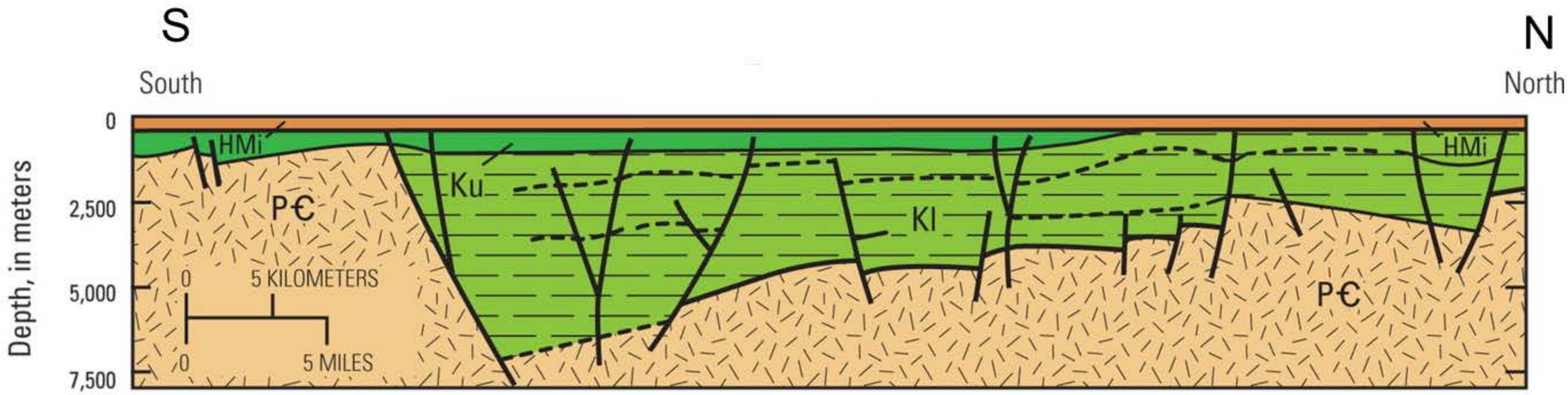
Figure 11. Central African Rift System, Stratigraphic Column



AAPG Bulletin, August 1993, v. 77, p. 1405-1434

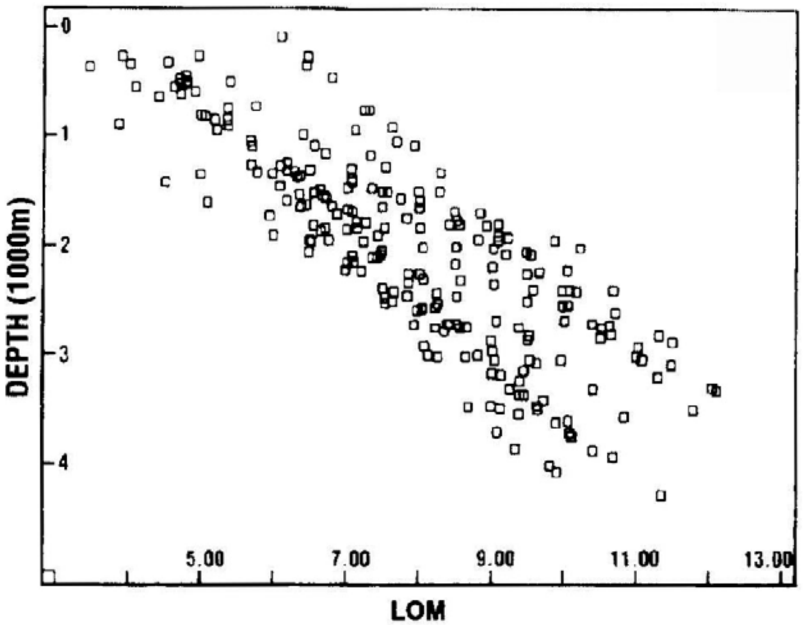
Source: Genik, 1993

Figure 12. Bongor Basin South-to-North Cross-Section



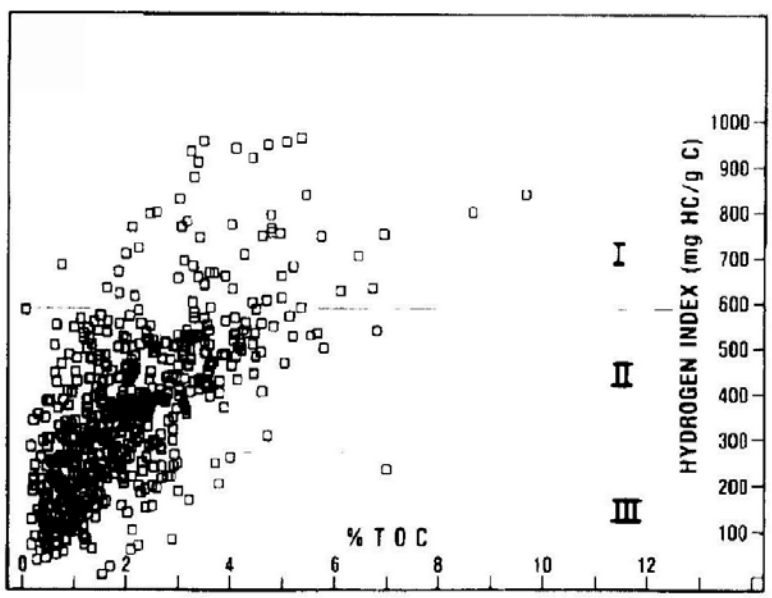
Source: Modified after Genik (1992) and USGS (2011).
North-to-south schematic geologic cross-section of the western part of the Bongor Basin showing sedimentary fill.
Location of cross-sections shown in Figure 10. Kl, Lower Cretaceous; Ku, Upper Cretaceous.

Figure 13. Level of Organic Maturation (LOM) vs. Depth: Lower Cretaceous Shale



Source: Genik, 1993
Level of organic maturation (LOM) vs. depth. LOM values normalized against vitrinite reflectance, thermal alteration index, and/or Tmax from Lower Cretaceous shales for wells in Bongor, Doba and Doseo basins.

Figure 14. Hydrogen Index (HI) vs. TOC Analyzed by Pyrolysis: Lower Cretaceous Shale



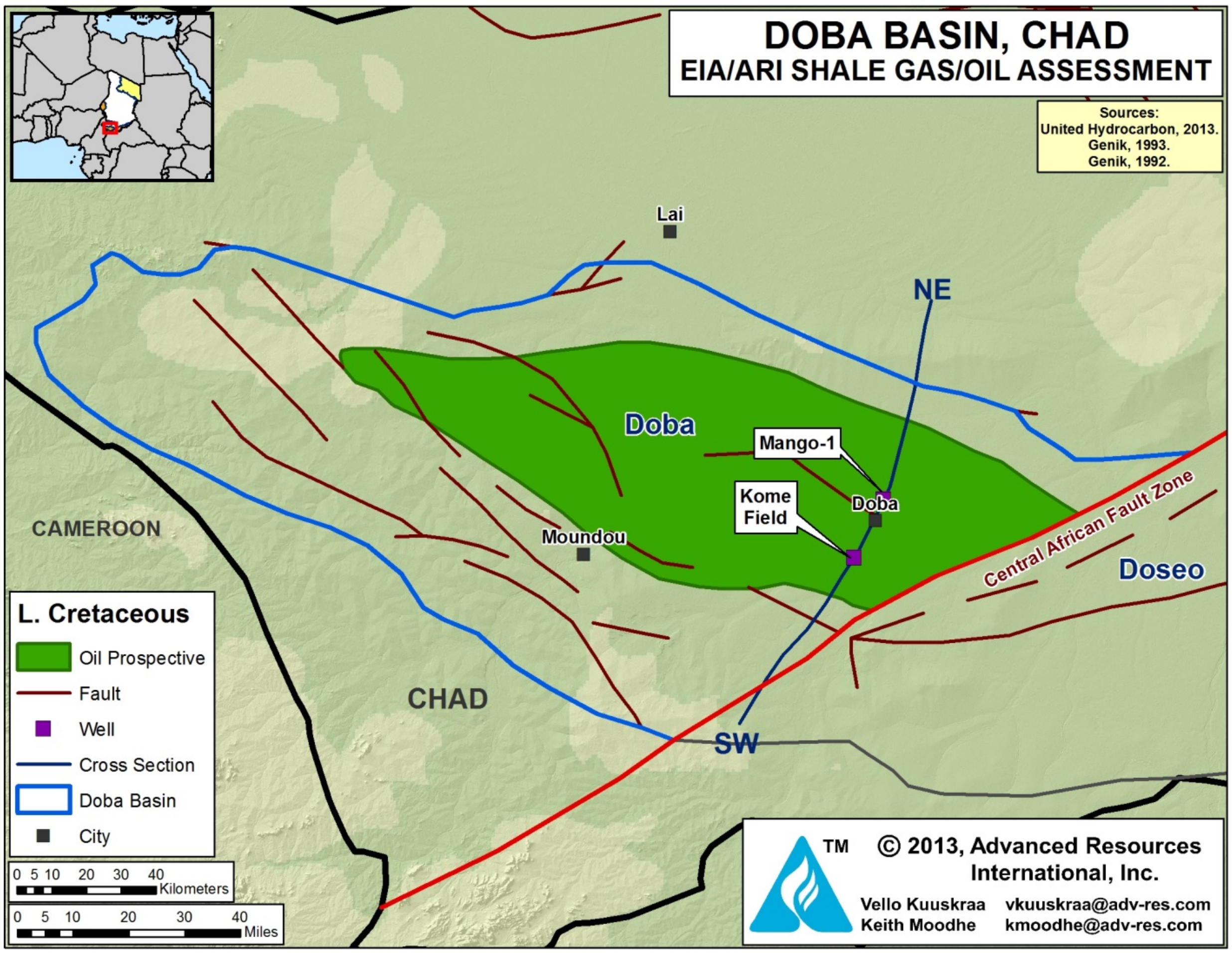
Source: Genik, 1993
Hydrogen index (HI) vs. TOC analyzed by pyrolysis. Includes 577 Lower Cretaceous shale cuttings and sidewall core samples for wells in Bongor, Doba and Doseo basins. Note predominance of Type III kerogen (HI < 300).

3. DOBA BASIN

3.1 Introduction and Geologic Setting

The Doba Basin is the easternmost of the Central African rift basins in southern Chad. The basin encompasses a 9,100-mi^2 area along the southern border of Chad and the Central African Republic. The basin is bounded on the east by the Central African Fault Zone and on the north, south and west by a series of deep-seated faults, Figure 15.

Figure 15. Doba Basin Prospective Area for Lower Cretaceous Shale



Source: ARI, 2013

The Doba Basin contains the initial set of oil fields producing in Chad, namely the Miandoum (in 2003) as well as the Kome and Bolobo (in 2004). These were followed by Nya (in 2005), Moundouli (in 2006) and Maikeri (in 2007), Figure 16.[6] Oil production from these fields is transported for export by the 655-mile Chad-Cameroon pipeline.

The basin contains a thick sequence of Lower Cretaceous sediments deposited directly on the Pre-Cambrian, as illustrated by the generalized stratigraphic column for the Doba Basin, Figure 17.[2]

The Lower Cretaceous sediment thickness ranges from about 1,000 m on the north to nearly 5,000 m in the basin center, as shown by the northeast-to-southwest cross-section, Figure 18.[1] Much of this Lower Cretaceous sediment is below the 5,000 m cut-off used by this study.

3.2 Reservoir Properties (Prospective Area)

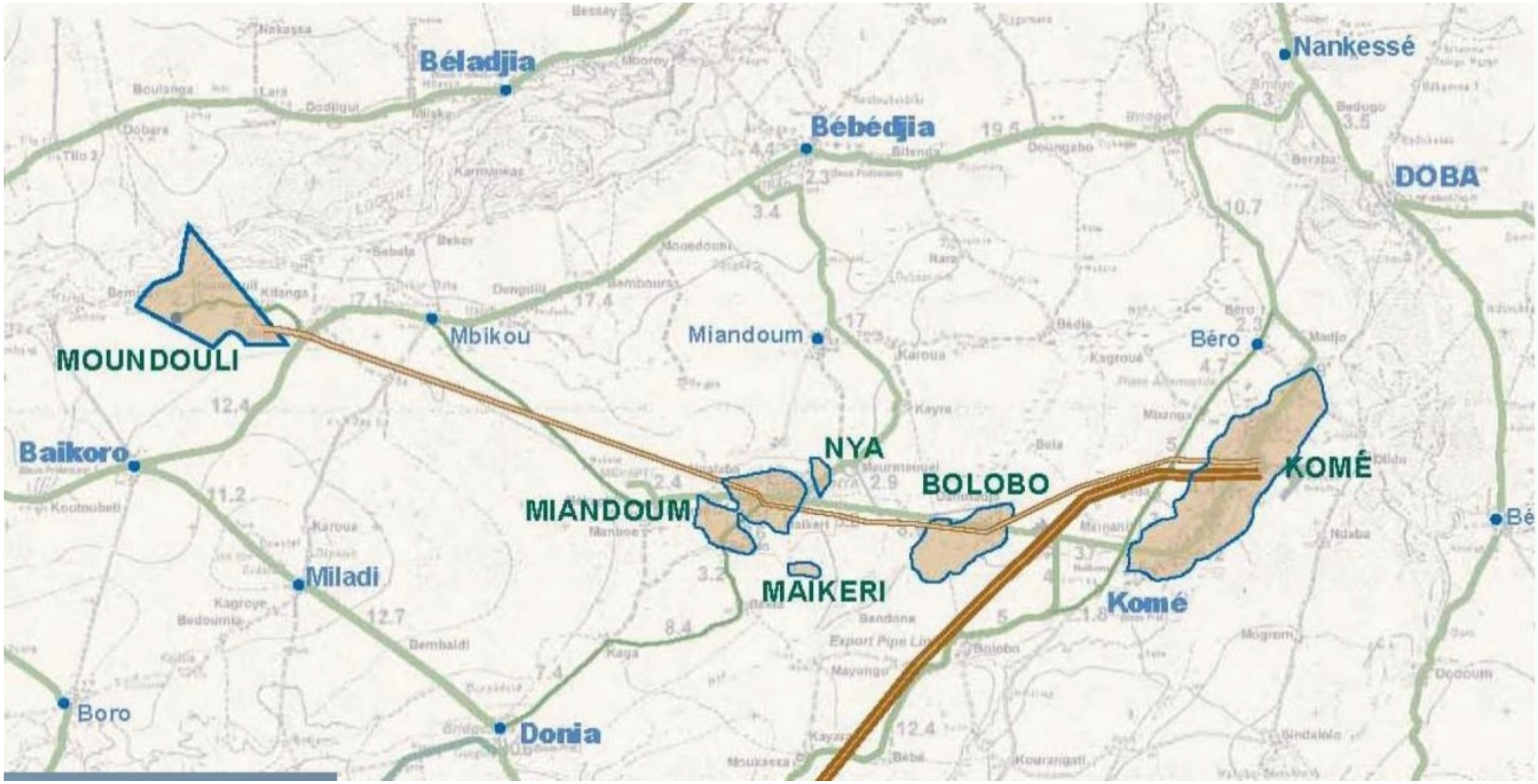
The higher quality, thicker sequence of shales in the Doba Basin are the Lower Cretaceous shallow marine-paralic dark shales. These shales occur as a series of thin, stacked beds that, when aggregated, comprise significant net feet of organic-rich pay.

The depth of the Lower Cretaceous shale oil prospective area of the Doba basin (thermal maturity ranges from 0.7% to 1.0%) ranges from 8,200 ft along the edge of the basin to 16,400 ft in the deep basin center. The thermal maturity of the deeper sediments places the Cretaceous-age source rock into the middle to late oil window. (Recent deep exploration drilling has identified the presence of light oil, 34^o to 39^o API, with notable associated gas (600 to 700 scf/barrel).

The organic-rich basal shale covers an interval of about 200 m, with a net shale thickness of about 100 m in a sequence of 2 to 10 m high TOC segments dispersed within the larger source rock interval, Figure 19.[2] The TOC content of the organic-rich basal shale ranges from 1 to over 14%, averaging 2% to 3%. The organic matter is mostly Type III kerogen derived from plant materials mixed with Type I kerogen derived from fresh water algae and bacteria.

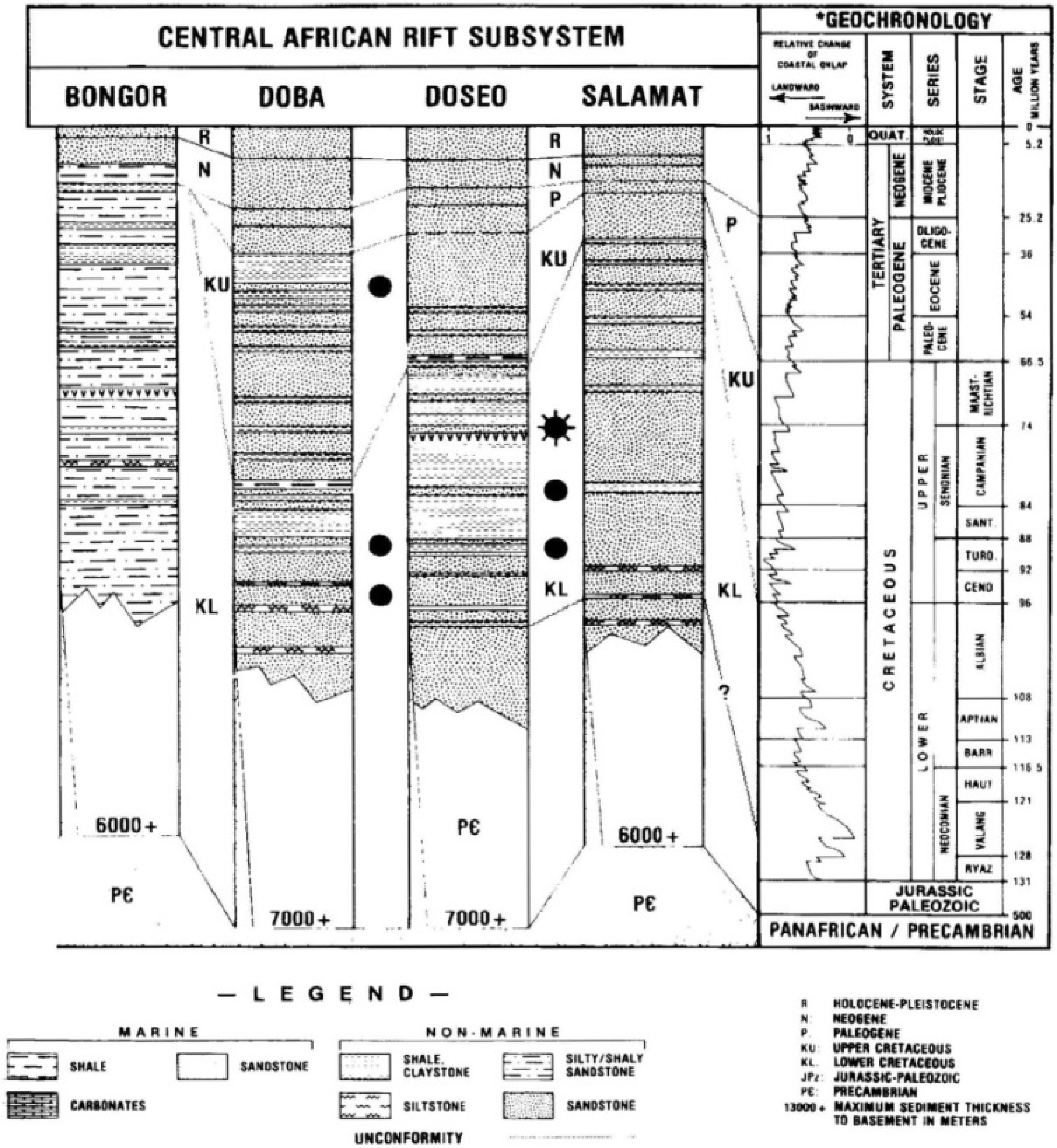
The temperature gradient in the Doba Basin averages 1.4^o to 1.6^{o}F per 100 ft. Locally, the temperature gradients may reach 2^o to 3^{o}F per 100 ft.

Figure 16. Producing Oil Fields, Doba Basin



Source: de Mahieu, S., 2008 (Green line = road; brown line = pipeline; blue circle = city)

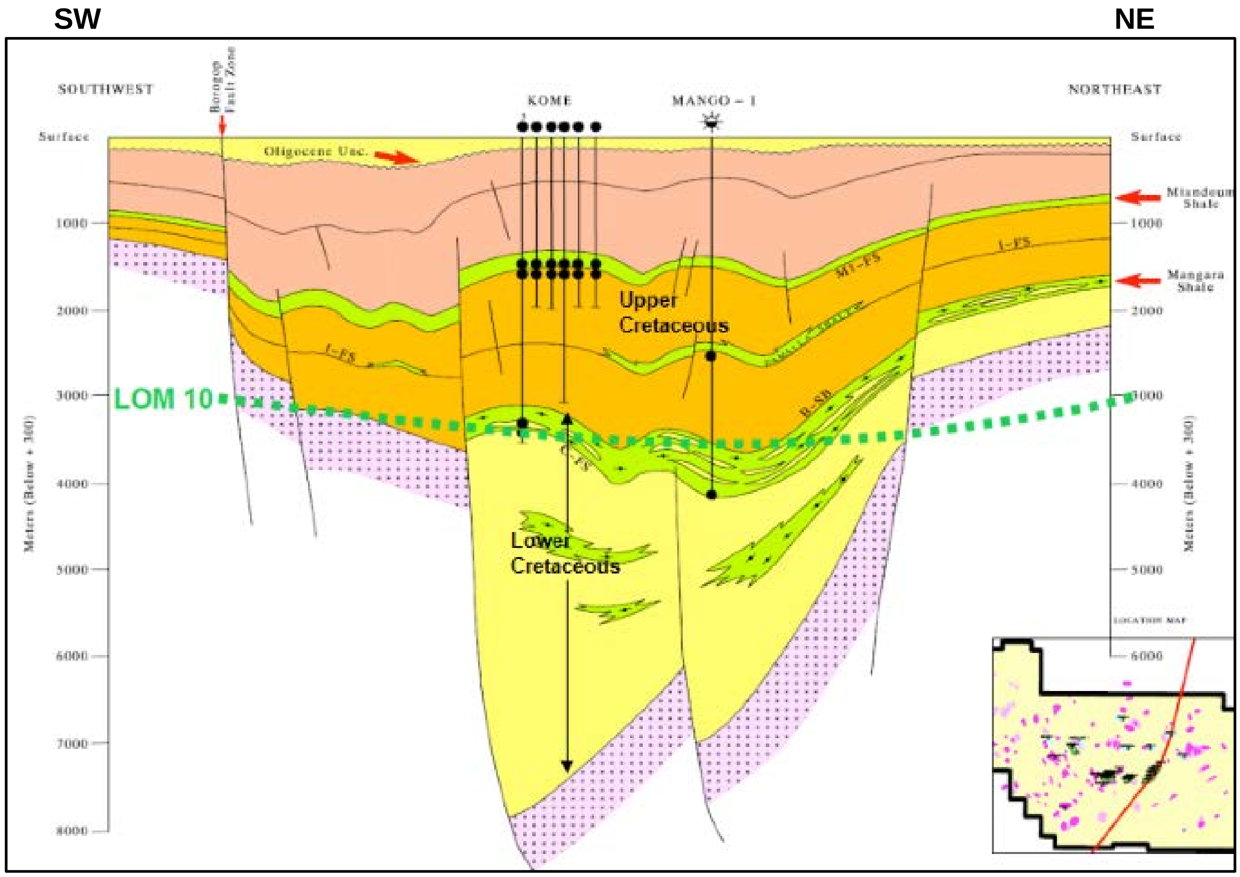
Figure 17. Central African Rift System, Stratigraphic Column



AAPG Bulletin, August 1993, v. 77, p. 1405-1434

Source: Genik, 1993

Figure 18. Doba Basin SW-to-NE Cross-Section



Source: United Hydrocarbon International Corp., 2013

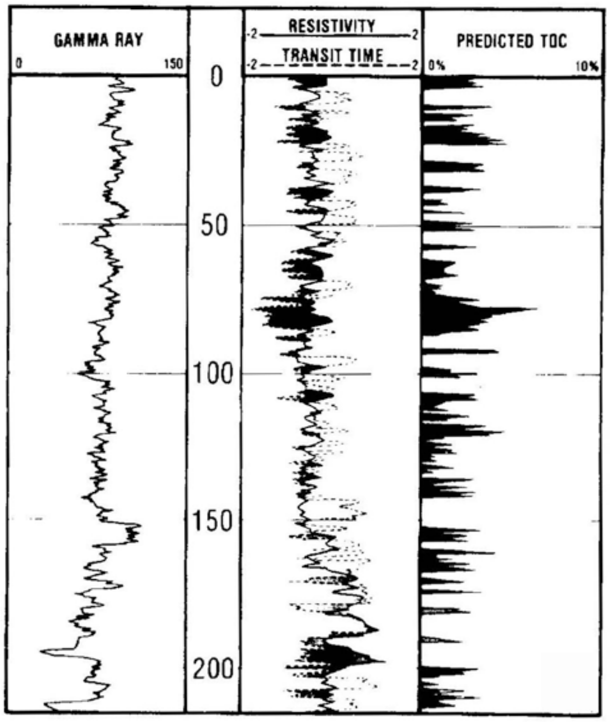
3.3 Resource Assessment

The Lower Cretaceous shale in the Doba Basin, within its 3,450 mi^2 oil prospective area, has a resource concentration of 46 million barrels/mi^2.

The risked resource in-place for the oil prospective area of the Lower Cretaceous shale in the Doba Basin is 80 billion barrels of oil and 74 Tcf of associated gas. With concerns about the ability to fully contact the interbedded, organic-rich and lean shale interval, but otherwise favorable reservoir properties, we estimate a risked, technically recoverable shale resource of 3.2 billion barrels of oil and 6 Tcf of associated gas.

Figure 19. Relationship of Gamma Ray and Resistivity Log to TOC: Lower Cretaceous Shales

Doba Basin



Source: Genik, 1993

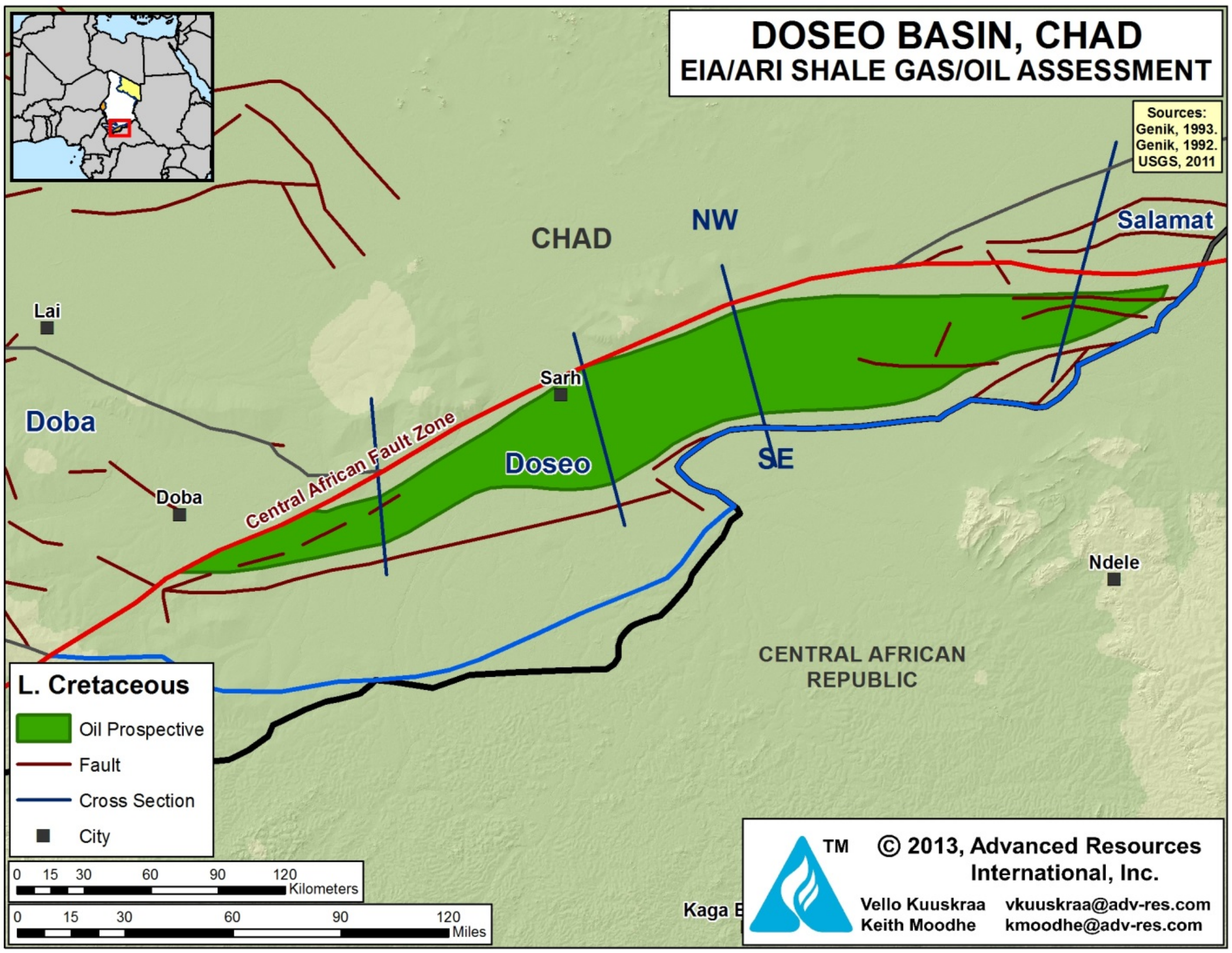
Note: Depth in meters, gamma ray logs in API units, resitivity logs in ohms with transit time in micro seconds per foot, and TOC volumes in weight percent.

4. DOSEO BASIN

4.1 Introduction and Geologic Setting

The Doseo Basin, covering an area of 13,600 mi^2, is located in southern Chad. It is flanked on the east by the Doba Basin and on the west by the Salamat Basin, Figure 20. The Central African Fault Zone forms the northern border of the Doseo Basin and a series of deep-seated faults form its southern boundary.

Figure 20. Doseo Basin Prospective Area for Lower Cretaceous Shale



Source: ARI, 2013

The Doseo Basin contains eleven exploration wells, leading to four recent drilled conventional oil discoveries - - Kibra, North Sako, Tega and Mauku. These discoveries have been tested but not yet placed on production.

The Doseo Basin contains a thick package of Lower Cretaceous sediments and organic-rich shales deposited directly on the Pre-Cambrian, as shown on a generalized stratigraphic column for the Doseo Basin, Figure 21.[2]

The Lower Cretaceous sediments in the Doseo Basin are unusually thick, on the order of 2,500 to 3,000 m across much of the basin, as illustrated by the northwest-to-southeast cross-section, Figure 22.[3,5]

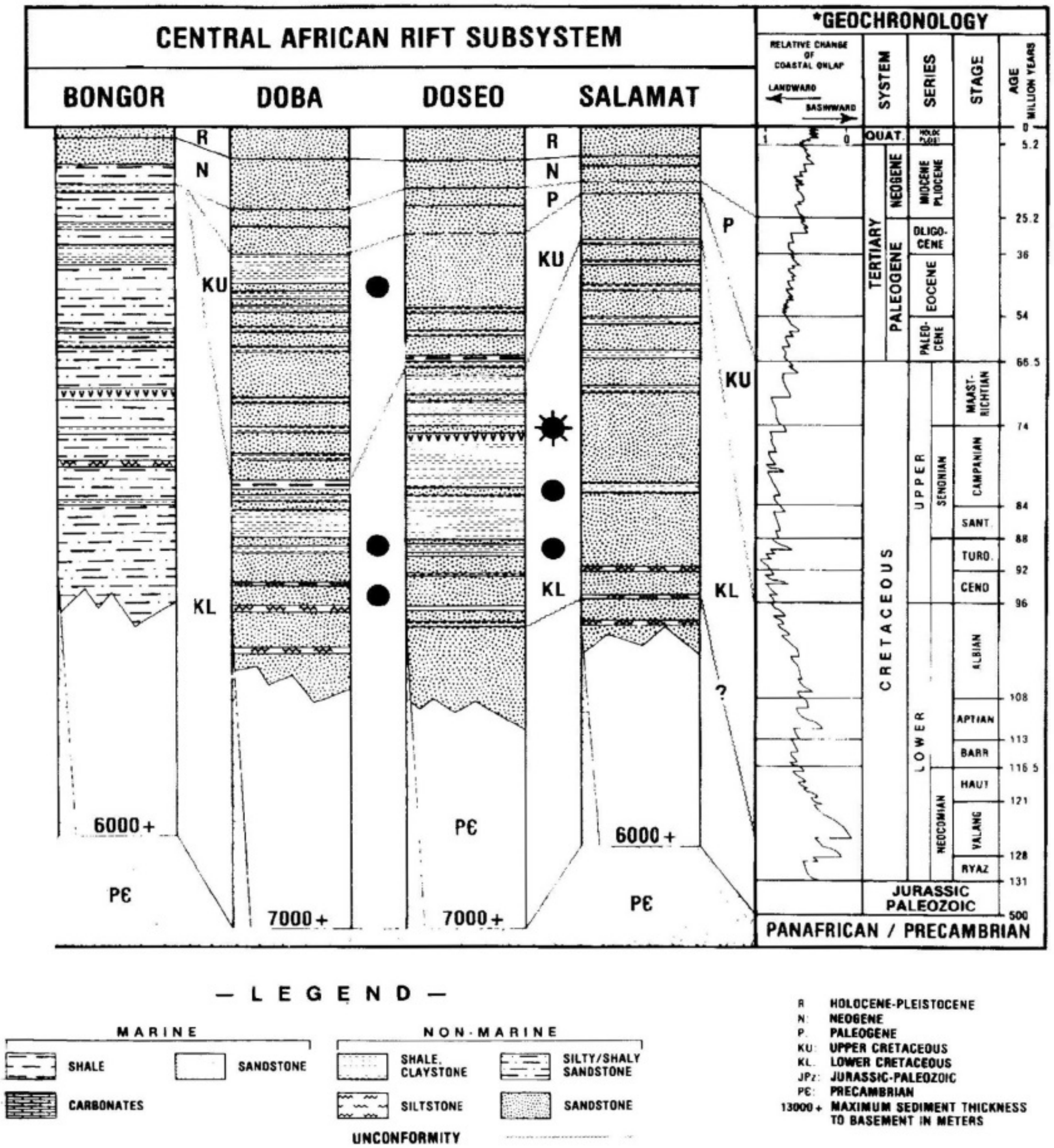
Like the Bongor and the Doba basins, the Lower Cretaceous shales are predominantly Type III and Type I kerogen. The TOC of the shale ranges from 2% to over 5%. The thermal maturity of the Lower Cretaceous shale increases with depth, reaching the oil window at 7,500 ft, with the base of the oil window at 16,400 ft (the depth cut-off for the study). Exploration wells drilled into the shallower sediments flowed medium to light sweet crude.

4.2 Reservoir Properties (Prospective Area)

The depth of the oil prospective area of the Doseo Basin (thermal maturity range 0.7% to 1.0% Ro) of the Lower Cretaceous shale ranges from 7,500 ft along the northern and southern basin boundaries (top of the oil window) to 16,400 ft (depth limit of study) in the center of the basin, averaging 12,000 ft.

The organic-rich lacustrine shale has a net thickness of 460 ft within a gross interval of 660 ft and has an average TOC of 3%, Figure 23.[2] The reservoir pressure gradient is assumed to be normal, while the reservoir temperature gradient is about 1.5^{o}F/100 ft.

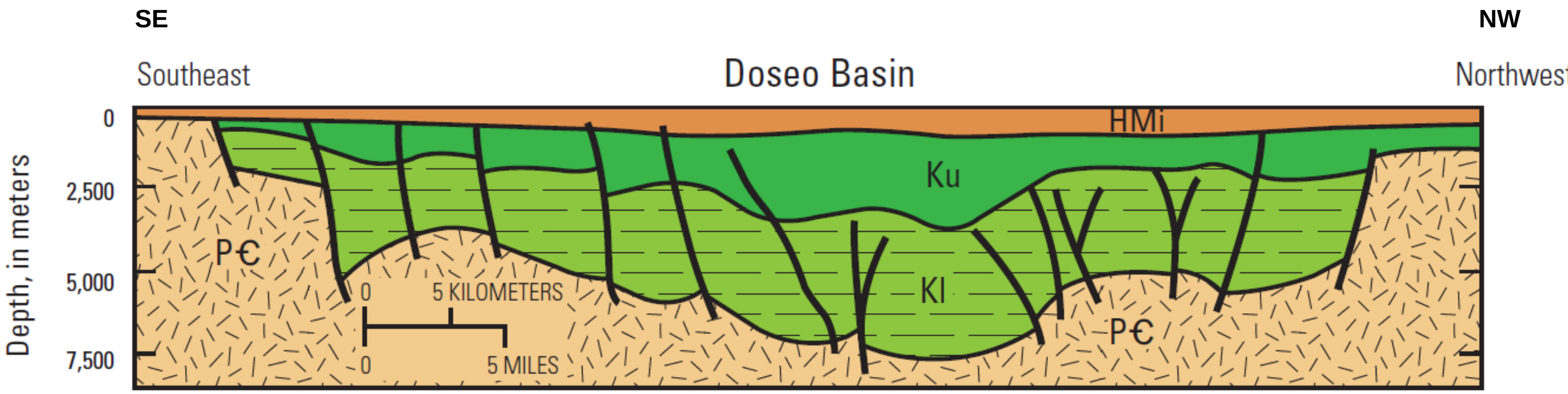
Figure 21. Central African Rift System, Stratigraphic Column



AAPG Bulletin, August 1993, v. 77, p. 1405-1434

Source: Genik, 1993

Figure 22. Doseo Basin SE-to-NW Cross-Section



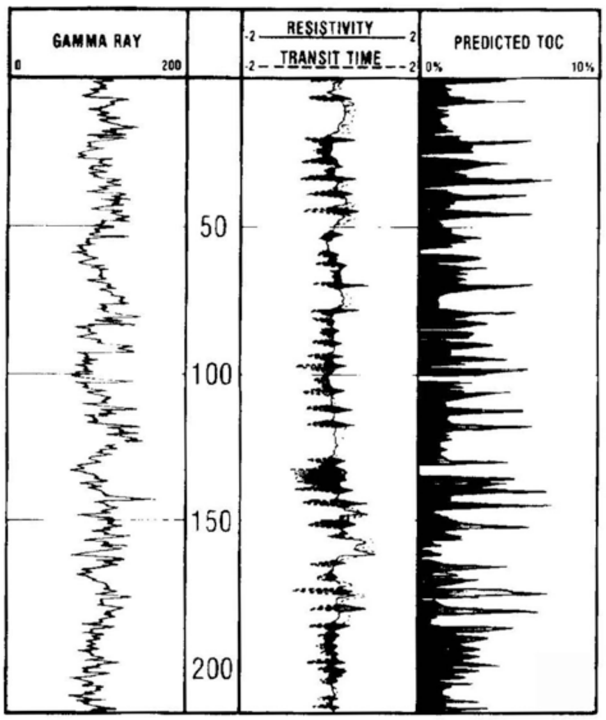
Source: Modified after Genik (1992) and USGS (2011)
Southeast-to-Northwest schematic cross-section of western Doseo Basin showing sedimentary fill.
Location of cross-section shown in Figure 1. Kl, Lower Cretaceous; Ku, Upper Cretaceous.

4.3 Resource Assessment

The Lower Cretaceous shale in the Doseo Basin has a 5,530 mi^2 area prospective for oil with a resource concentration of 64 million barrels/mi^2 (plus associated gas).

The risked resource in-place for the Lower Cretaceous shale prospective area is 178 billion barrels of shale oil and 165 Tcf of associated gas, with 7.1 billion barrels of oil and 13 Tcf of associated gas as the risked, technically recoverable resources.

Figure 23. Relationship of Gamma Ray and Resistivity Logs to TOC: Lower Cretaceous Shales Doseo Basin



Source: Genik, 1993
Note: Depth in meters, gamma ray logs in API units, resitivity logs in ohms with transit time in micro seconds per foot, and TOC volumes in weight percent.

5. SALAMAT BASIN

5.1 Introduction and Geologic Setting

The Salamat Basin is the easternmost of the four Central African Rift System basins. The Chad portion of the Salamat Basin is bounded on the north by the Central African Fault Zone, on the west by the Doseo Basin, and on the east and south by the Chad and Central African Republic (CAR) border.

5.2 Reservoir Properties (Prospective Area)

Our assessment of the lightly explored Salamat Basin is that the bulk of its prospective area is in the southeastern portion of the basin, in the CAR.

5.3 Resource Assessment

Because of the bulk of the potential shale oil and shale gas resource in the Salamat Basin is in CAR, we have not conducted a quantitative assessment of the Salamat Basin.

6. ERDIS BASIN

6.1 Introduction and Geologic Setting

The Erdis Basin is a large, intra-cratonic basin located in northern Chad. The basin extends northward into Libya where it is called the Kufra Basin and into Sudan where it is called the Mourdi Basin. The Paleozoic structural and deposition history of the Erdis Basin is similar to that of the Murzuq Basin in Libya where exploration for shale resources is underway. However, there is considerable uncertainty as to the presence of sufficiently organic-rich source rocks in this basin.

The Lower Silurian Tannezuft Formation is described as up to 130 m thick in outcrops at the basin margins, Figure 24.[7] However, the basal section of the Tannezuft Formation containing the Silurian "hot shale" in the Murzuq Basin appears to be missing in outcrops along the northern and eastern margins of the basin.[8]

In addition, the "hot shale" unit was absent in exploration wells drilled to date in the northern portion of this basin in Libya, having been replaced by siltstones and sandstones. The absence of lower Silurian shales in the Erdis Basin exploration wells - - A1-NC-43 and B1-NC43 - - drilled by AGIP in the late 1970s and early 1980s suggests that this area may have been deposited as a sandy delta during the early Silurian. As such, this area may be the westward continuation of the sandy Lower Silurian in western Egypt where the Tannezuft basal "hot shale" is also absent, Figure 25.[8]

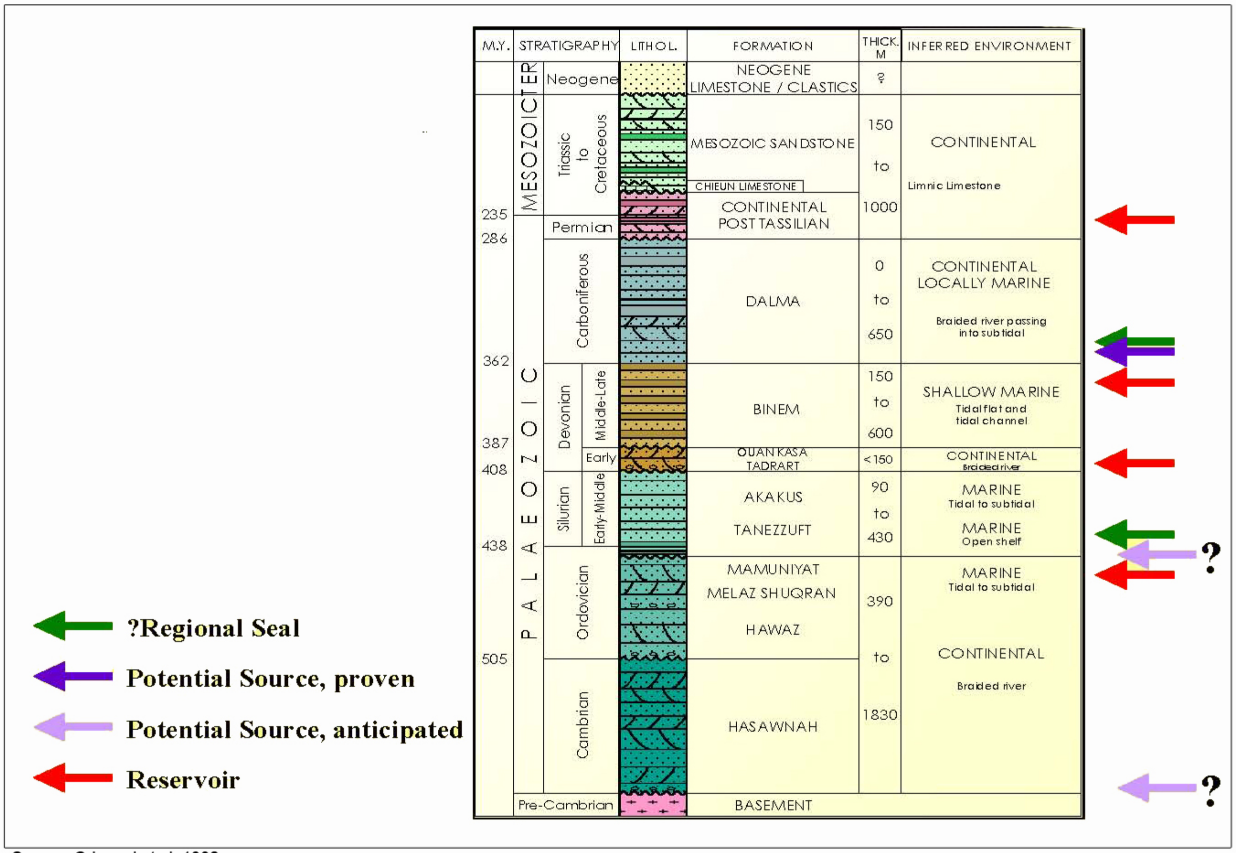
6.2 Reservoir Properties (Prospective Area)

Lower Silurian, organic-rich shales may be present in the western part of the Erdis Basin.[9] However, the areal distribution of this shale unit is laterally highly variable with the Silurian basal "hot shale" occurrences deposited as linear features and patches, surrounded by areas in which the basal "hot shale" is absent.[8] As such, we have not identified a prospective shale gas or shale oil area in the Erdis Basin.

6.3 Resource Assessment

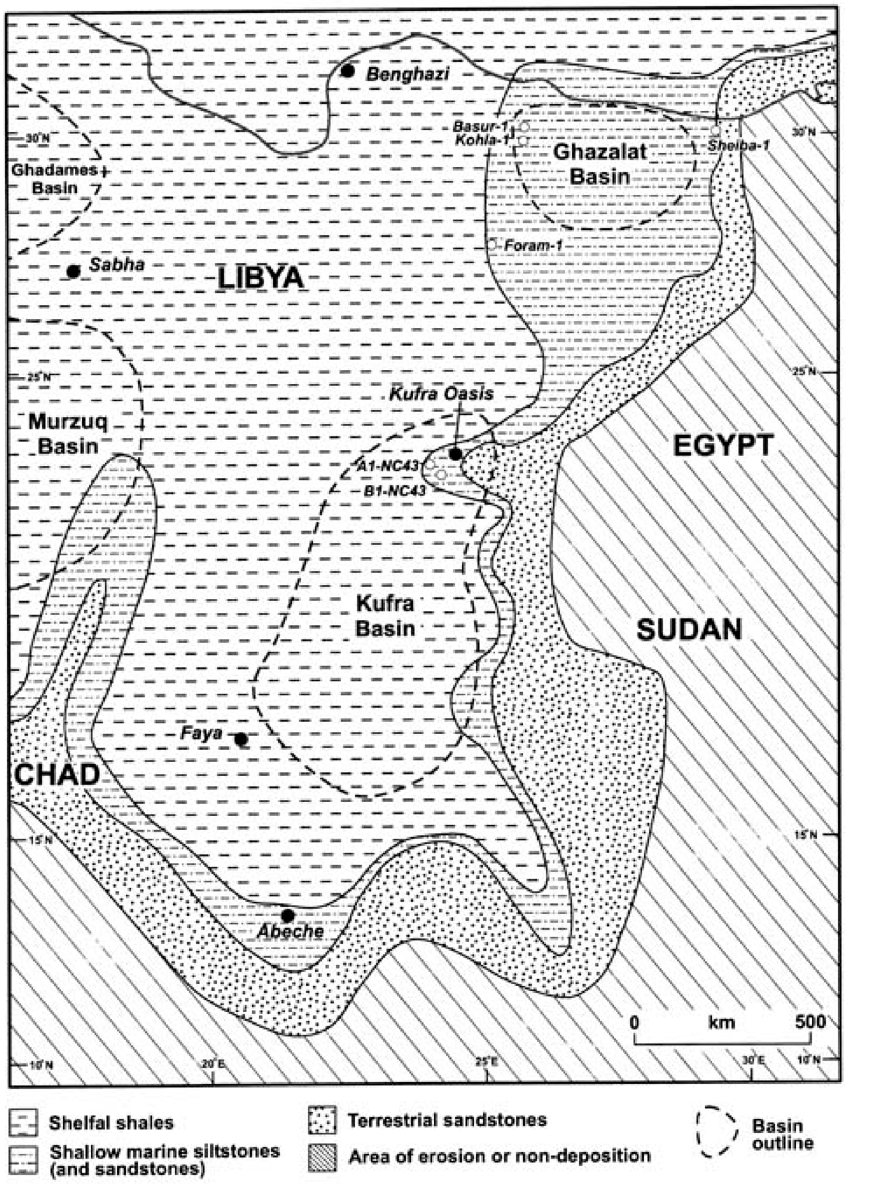
Because of the speculative nature of the shale deposition, we have not conducted a quantitative assessment of the shale resources of the Erdis Basin.

Figure 24. Stratigraphic Column of the Erdis Basin



Source: Grignani et al. 1992

Figure 25. Early Silurian Paleogeography of the Kufra Basin



Source: Luning et al. 1999.

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