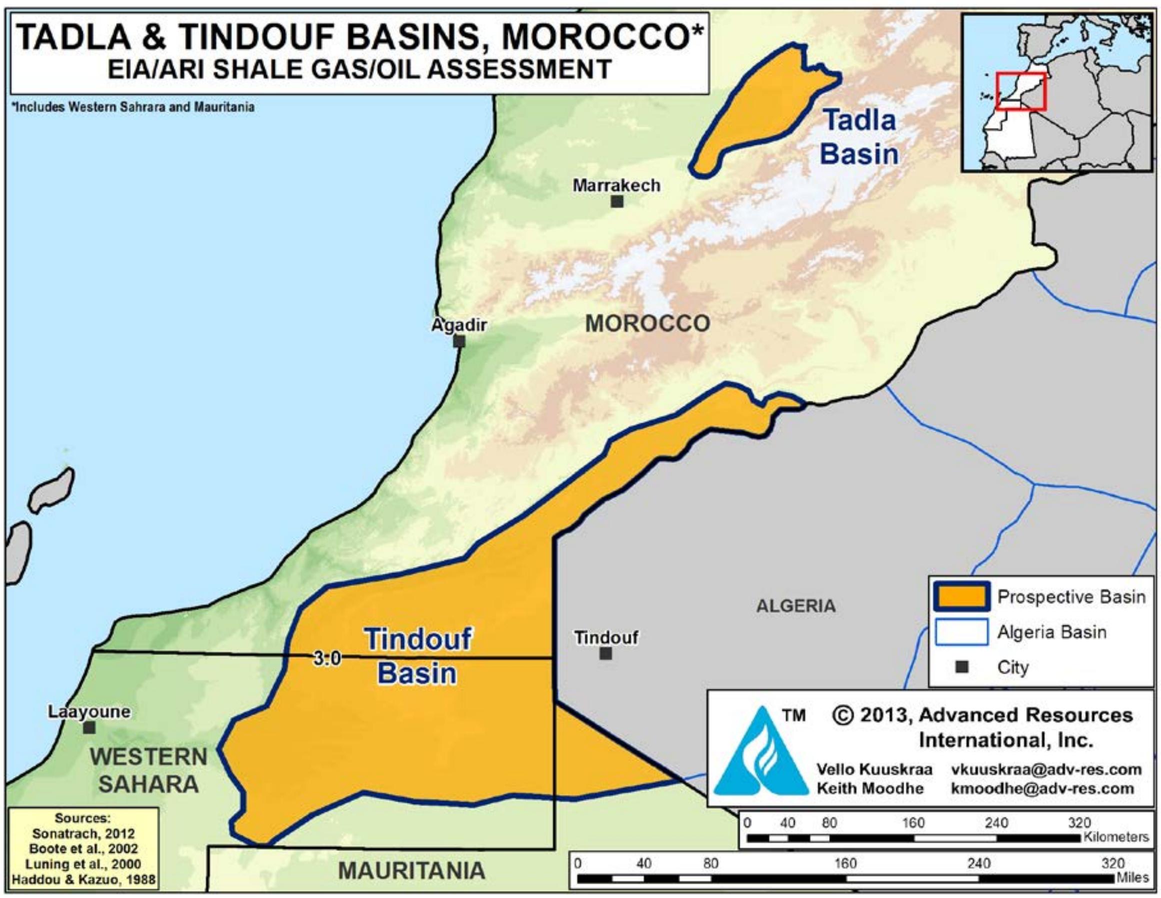
XIV. MOROCCO (INCLUDING WESTERN SAHARA AND MAURITANIA)

SUMMARY

In addition to large accumulations of Late-Cretaceous immature oil shale (kerogen) at depths suitable for surface mining[1], Morocco and its two neighboring countries, Mauritania and Western Sahara, also possess organic-rich Silurian- and Devonian-age shale gas and shale oil potential in the Tindouf and Tadla basins, Figure XIV-1. Mapping and resource characterization of these shales is challenging because regional deformation, erosion and subsidence of the shale deposits have led to their discontinuous and complex present day distribution.

Figure XIV-1. Shale Gas Basins of Morocco, Western Sahara and Mauritania



Source: ARI, 2013.

ARI estimates that the Tindouf and Tadla basins contain risked shale gas in-place of 95 Tcf, with 20 Tcf of risked, technically recoverable shale gas resources, Table XIV-1. In addition, these two basins contain risked shale oil/condensate in-place of 5 billion barrels, with 0.2 billion barrels of risked, technically recoverable shale oil/condensate resources, Table XIV-2.

Table XIV-1. Reservoir Properties and Shale Gas Resources of Morocco, Sahara Desert and Mauritania

Basic Data	Basin/Gross Area		Tindouf (77,000 mi^2)			Tadla (2,800 mi^2)
	Shale Formation		L. Silurian			L. Silurian
	Geologic Age		L. Silurian			L. Silurian
	Depositional Environment		Marine			Marine
Physical Extent	Prospective Area (mi^2)		2,020	4,670	12,380	1,670
	Thickness (ft)	Organically Rich	60	60	60	328
		Net	54	54	54	197
	Depth (ft)	Interval	6,600 - 11,000	6,600 - 13,000	6,600 - 14,000	3,280 - 9,840
		Average	9,000	10,000	11,000	6,560
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Underpress.
	Average TOC (wt. %)		4.0%	4.0%	4.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	2.80%	2.25%
	Clay Content		Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		6.8	18.9	22.0	49.0
	Risked GIP (Tcf)		2.7	17.7	54.5	20.5
	Risked Recoverable (Tcf)		0.3	3.5	13.6	3.1

Table XIV-2. Reservoir Properties and Shale Oil Resources of Morocco, Sahara Desert and Mauritania

Basic Data	Basin/Gross Area		Tindouf (77,000 mi^2)	
	Shale Formation		L. Silurian	
	Geologic Age		L. Silurian	
	Depositional Environment		Marine	
Physical Extent	Prospective Area (mi^2)		2,020	4,670
	Thickness (ft)	Organically Rich	60	60
		Net	54	54
	Depth (ft)	Interval	6,600 - 11,000	6,600 - 13,000
		Average	9,000	10,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		4.0%	4.0%
	Thermal Maturity (% Ro)		0.85%	1.15%
	Clay Content		Medium	Medium
Resource	Oil Phase		Oil	Condensate
	OIP Concentration ($MMbbl/mi^2$)		7.9	1.7
	Risked OIP (B bbl)		3.2	1.6
	Risked Recoverable (B bbl)		0.16	0.08

INTRODUCTION

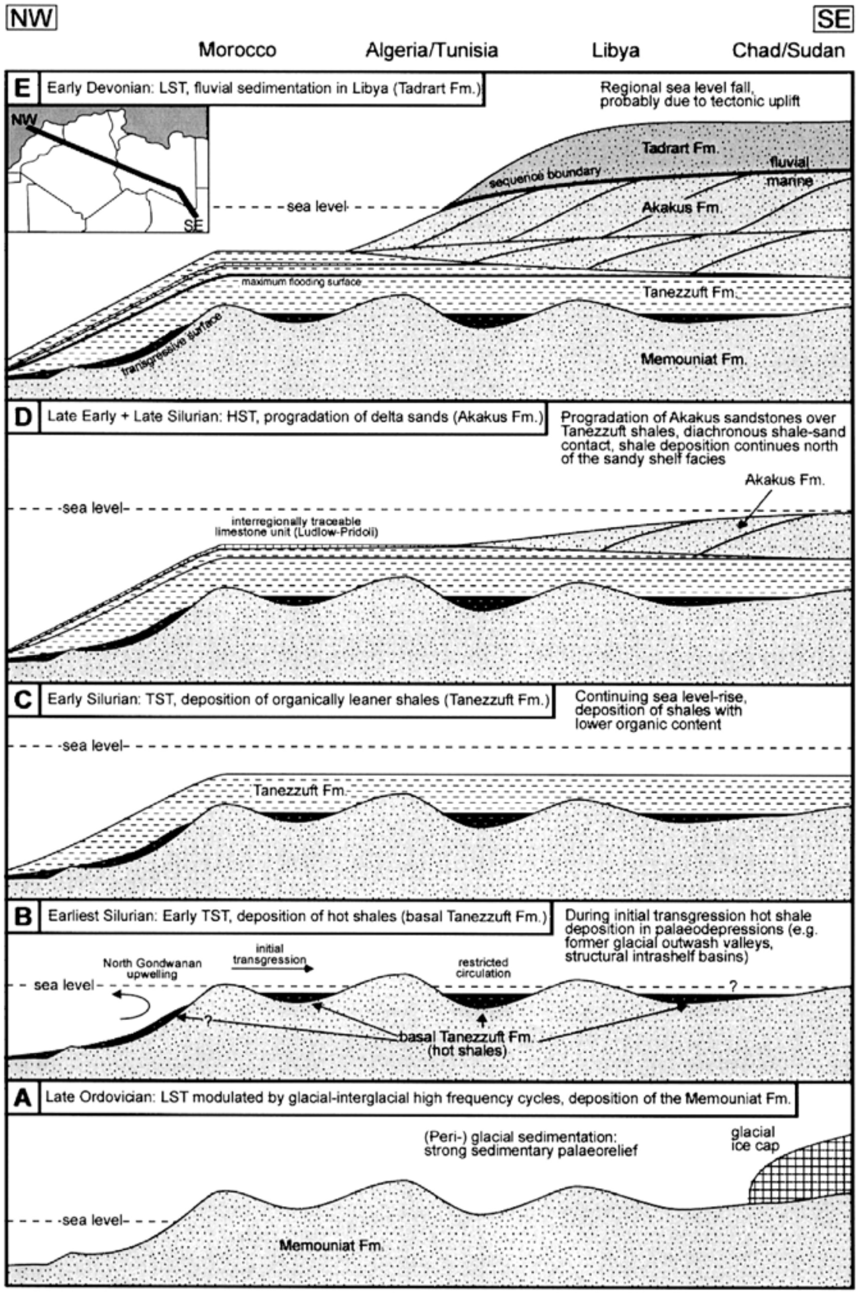
The primary shale resource on Morocco, Mauritania and Western Sahara is the lower Silurian “Hot Shale,” which consists of thin but very organic-rich layers of marine organic matter deposited during a regional anoxic event. Data from wells drilled across the country confirm the presence of organic-rich Silurian shales, although not always within the current formally established boundaries of hydrocarbon basins.

The presence of a thick Silurian section, observed in many Moroccan hydrocarbon basins, does not guarantee the presence of organic-rich shale, as areas that were regional highs during the early Silurian may not have received organic-rich sediments, Figure XIV-2.[2]

Accurately identifying promising shale basins and estimating their resource potential in such geologically complex areas requires significant amounts of data, which are not widely available in Morocco and its neighboring countries because of limited well drilling and data confidentiality. As this data becomes more publically available, a more rigorous shale gas and oil resource assessment of Morocco may be possible.

This report assesses the two basins which appear to have the highest potential for shale gas and oil resources based on publically available data: the Tindouf (Zag) Basin in the south of Morocco (extending into Algeria, Western Sahara, and Mauritania), and the central Moroccan Tadla Basin.

Figure XIV-2. Sedimentary Depositional Environment in Morocco, Ordovician-Devonian[2]



1. TINDOUF BASIN

1.1 Geologic Setting

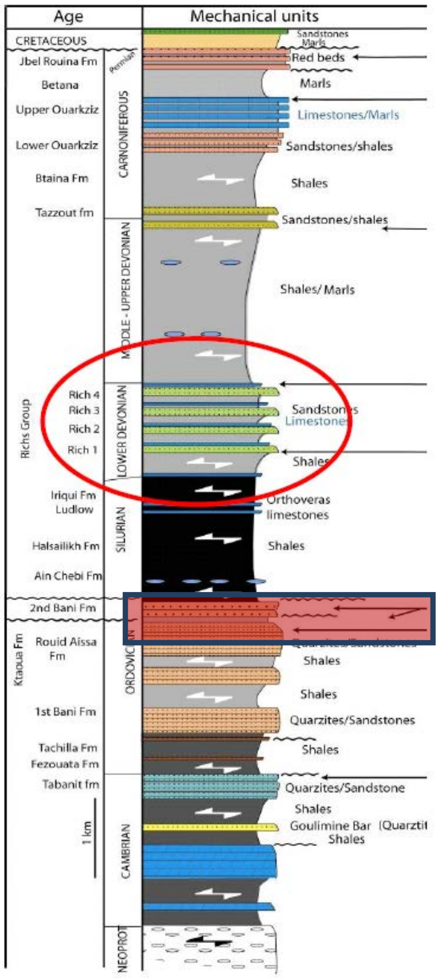
The Tindouf Basin is the westernmost of the major North African Paleozoic basins, covering a 31,660-mi^2 area in Morocco, Western Sahara and Mauritania. The basin is bounded by the Atlas Mountains and Ougarta Arch to the north and the Reguibate Massif in the south. Although once covered unconformably by a blanket of Mesozoic to early Tertiary sediments, the Paleozoic now crops out over much of the region. The Tindouf Basin is an asymmetric depression with a broad gentle southern flank and a steeply dipping, more structurally complex northern margin.

The Tindouf Basin was a large sediment depocenter from late Ordovician to Carboniferous time, accumulating multiple layers of organic-rich Silurian, Devonian (Frasnian) and Carboniferous (Visean) shales, Figure XIV-3.[3] However, these deposits were affected by the Hercynian deformation and the prospectivity of these shale formations is uncertain. High heat flow through the basin caused the Tindouf Basin shales to reach high maturity during the Carboniferous. Uplift and erosion of these shales may have caused significant underpressuring, as the shales were not buried deep enough to replenish hydrocarbons dissipated during the Hercynian orogeny.

This report focuses on the Lower Silurian "Hot Shale," which has greater data availability and higher confidence of remaining gas saturation in this shale interval. Through mapping of depth and thermal maturity, we have identified a 19,070-mi^2 prospective area in the Morocco, Mauritania and Western Sahara portion of the Tindouf Basin. The northern boundary of the prospective area is the 1,000-meter depth contour on the upthrusted northern portion of the basin, Figure XIV-4.[4] The southern boundary is the 0.7% R_o thermal maturity contour. The eastern boundary is the Algeria Border.

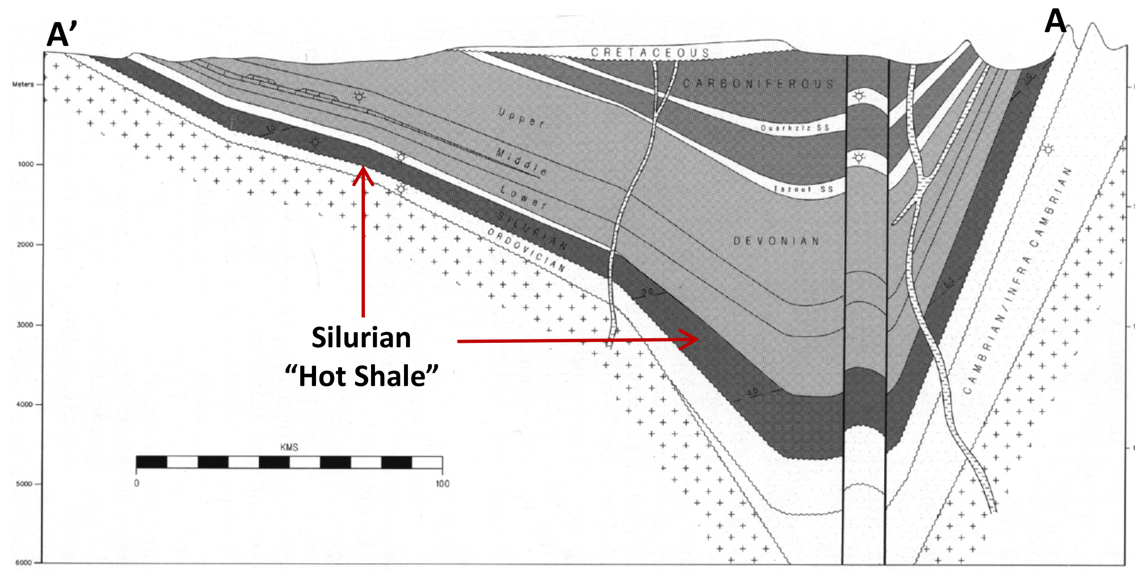
While the drilling density in the basin is extremely low, with an average of only one well per 5,000 mi^2, the data suggest that organic-rich, basal Silurian shales were deposited throughout the basin.[2] Additional well and seismic data have been collected by various international companies in partnership with Moroccan oil company, ONHYM, but these data are not yet in the public domain.

Figure XIV-3. Tindouf Basin Stratigraphic Column



Source: Longreach Petroleum Corporate Presentation, 2010

Figure XIV-4. Tindouf Basin Cross Section

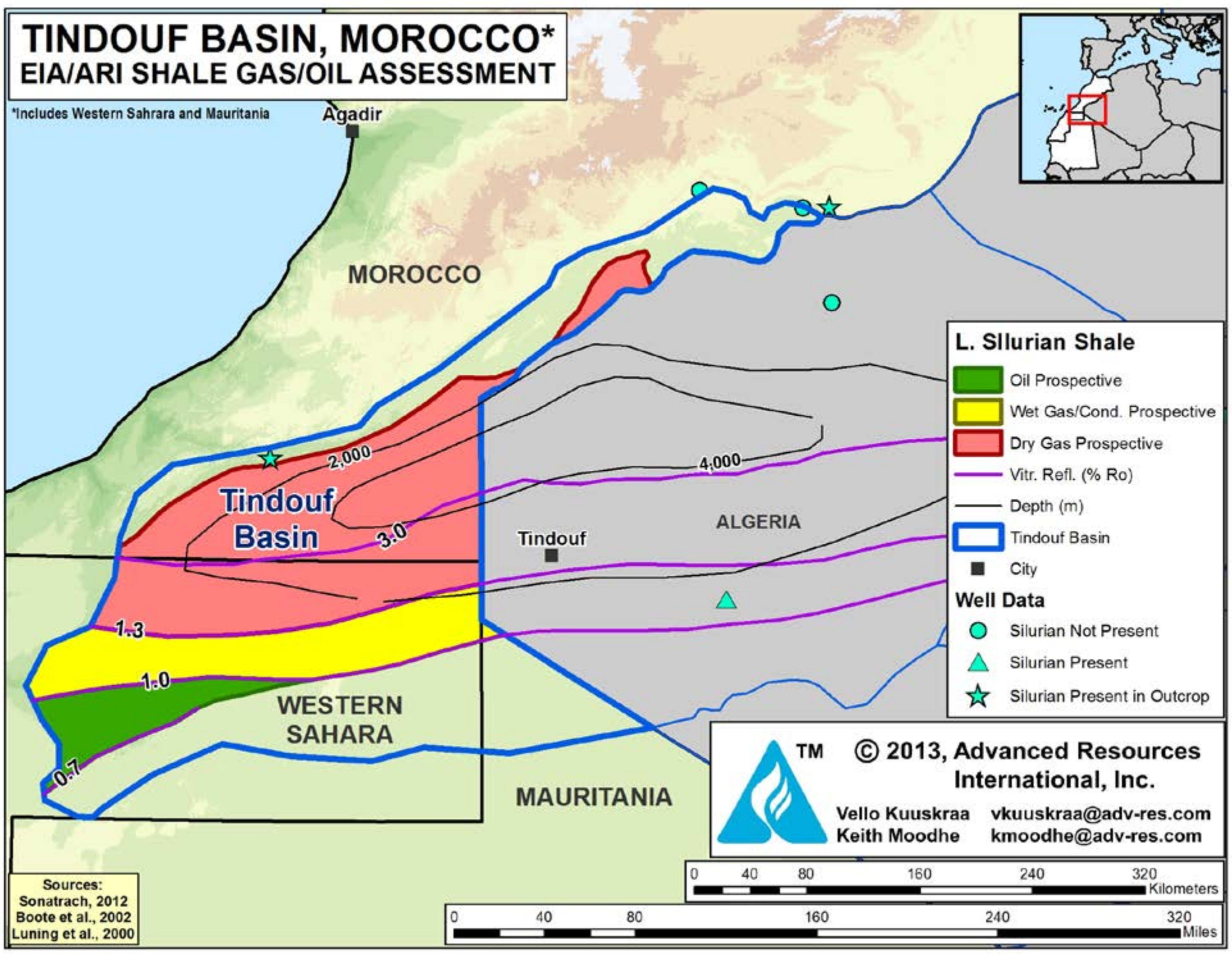


Source: Boote, 2002.

1.2 Reservoir Properties (Prospective Area)

Within the Tindouf Basin's prospective area, the depth to the Silurian "Hot Shale" ranges from 6,600 to 14,000 ft, Figure XIV-5. Present day TOC content ranges from 1% to 7%, averaging 4%. It is likely that the TOC content was higher during the time of hydrocarbon generation, due to the basin's very high thermal maturity.[5] Thermal maturity increases to the north across the basin, ranging from 0.7% to over 3% R_o.[4] Organic-rich net shale thickness is estimated at 54 ft, based on data from a well drilled in the southern flank of the basin.[6]

Figure XIV-5. Tindouf Basin Prospective Area, Morocco, Western Sahara and Mauritania



Source: ARI, 2013

1.3 Resource Assessment

We estimate that the wet and dry gas prospective area of the Silurian "Hot Shale" in the Morocco, Mauritania and Western Sahara portions of the Tindouf Basin has a resource concentration of 19 to 22 Bcf/mi^2. The oil prospective area of the Silurian "Hot Shale" has a resource concentration of 8 million barrels/mi^2 plus associated gas. While the shale formation is organic-rich, it is thin, limiting its resource concentration.

Within the overall 19,020-mi^2 prospective area, the Lower Silurian "Hot Shale" in the Tindouf Basin contains a 12,380-mi^2 area prospective for dry gas, a 4,670-mi^2 area prospective for wet shale gas and shale condensate, and a 2,020-mi^2 area prospective for shale oil. The risked shale gas in-place for the Tindouf Basin is estimated at 75 Tcf, with 17 Tcf as the risked, technically recoverable shale gas resource. In addition, the Tindouf Basin has an estimated 5 billion barrels of shale oil/condensate in-place, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

1.4 Recent Activity

The Moroccan national oil and gas company, ONHYM, has been evaluating the country's shale gas potential since mid-2010. It has plans to collect seismic data followed by the drilling of a shale gas exploration well. The well is proposed to be drilled in partnership with San Leon Energy (Ireland) and Longreach Oil and Gas (Canada) on the Zag exploration license.[7]

2. TADLA BASIN

2.1 Geologic Setting

The Talda Basin is a 2,800-mi^2 intra-cratonic basin located in central Morocco within the Moroccan Mesta. The basin contains nearly 16,500 feet of Paleozoic through Cenozoic sedimentary strata, Figure XIV-6. Paleozoic rocks dominate the sediments in this basin, except in areas where uplift has caused their erosion, Figure XIV-7. The Talda Basin is bounded by the Central Massif in the north, the Atlas Mountains in the east, the Jebiliet Massif in the south, and the Rehamna Massif in the west. The Fkih Ben Salah Fault divides the basin into a southeast section, characterized by complex tectonics including heavy folding and faulting, and a northwest section, with thick carboniferous strata and minor, infrequent faulting.[8]

As in the Tindouf Basin, regional uplifting during the Hercynian and Alpine events exposed the Silurian, Devonian and Ordovician shales after they had matured and begun to generate hydrocarbons. While these shales were subsequently buried on the western edge of the basin by approximately 6,500 ft of Cretaceous and Tertiary sediments, it is unlikely that the shales generated additional hydrocarbons after reburial.[8] As such, this basin is at high risk for underpressuring, although data are not available to confirm this assumption.

The 1,670-mi^2 prospective area of the Tadla Basin is bounded by the 1,000-m depth contour, various faults and the Atlas Mountain range to the east, Figure XIV-8. Little data are available in the southern portion of the basin where the prospective area is bounded by the apparent lack of organic-rich Silurian strata.

2.2 Reservoir Properties (Prospective Area)

The Lower Silurian “Hot Shale” in the Tadla Basin reaches maximum depth west of the Fkih Ben Salah Fault, ranging from 3,280 to 9,840 ft.[8] To the east, the shale becomes shallower. Average depth in the prospective area is estimated at 6,560 ft. Where it has not been eroded, the Silurian section can reach up to 800 feet thick, with over 300 feet of organic-rich shale, of which 200 ft is net shale.[9] TOC data from outcrops suggest that the organic content reaches 10-12%,[10] but deep well data from inside the prospective area indicates TOC values closer to 2%. The Silurian shale is thermally highly mature over the prospective area; R_o values of 1.5% to 3% place the shale in the dry gas window.[8]

Figure XIV-6. Tadla Basin Stratigraphic Column[8]

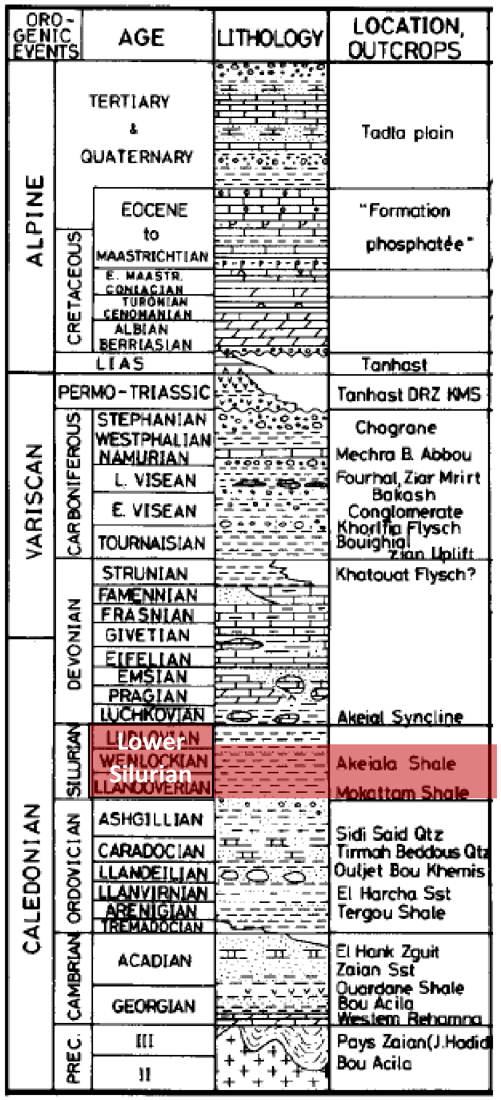
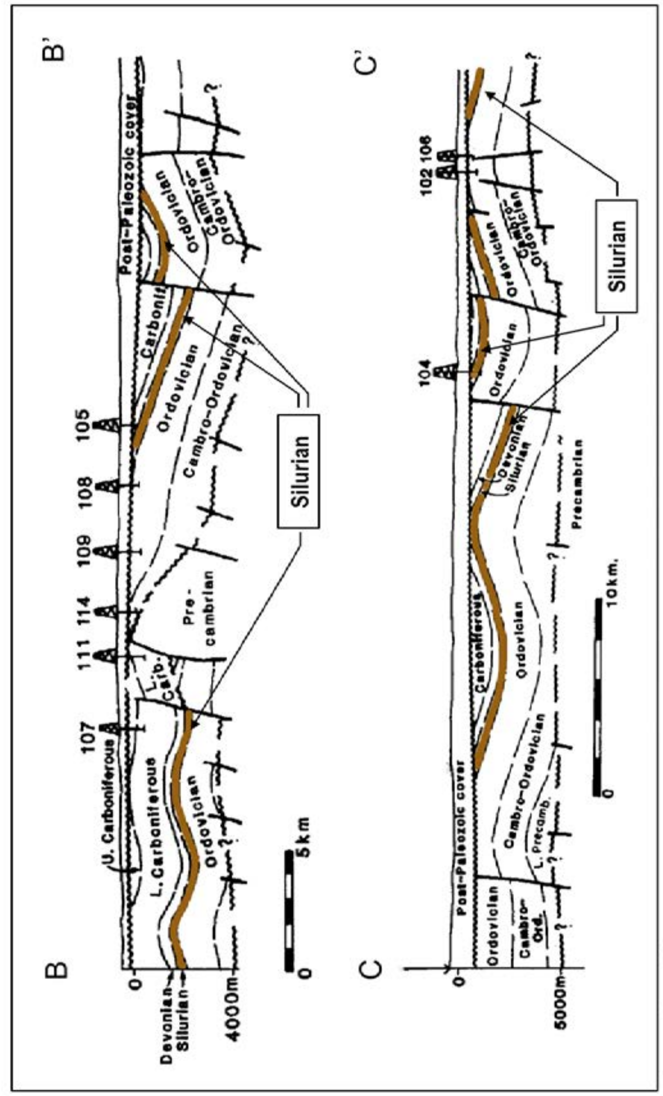
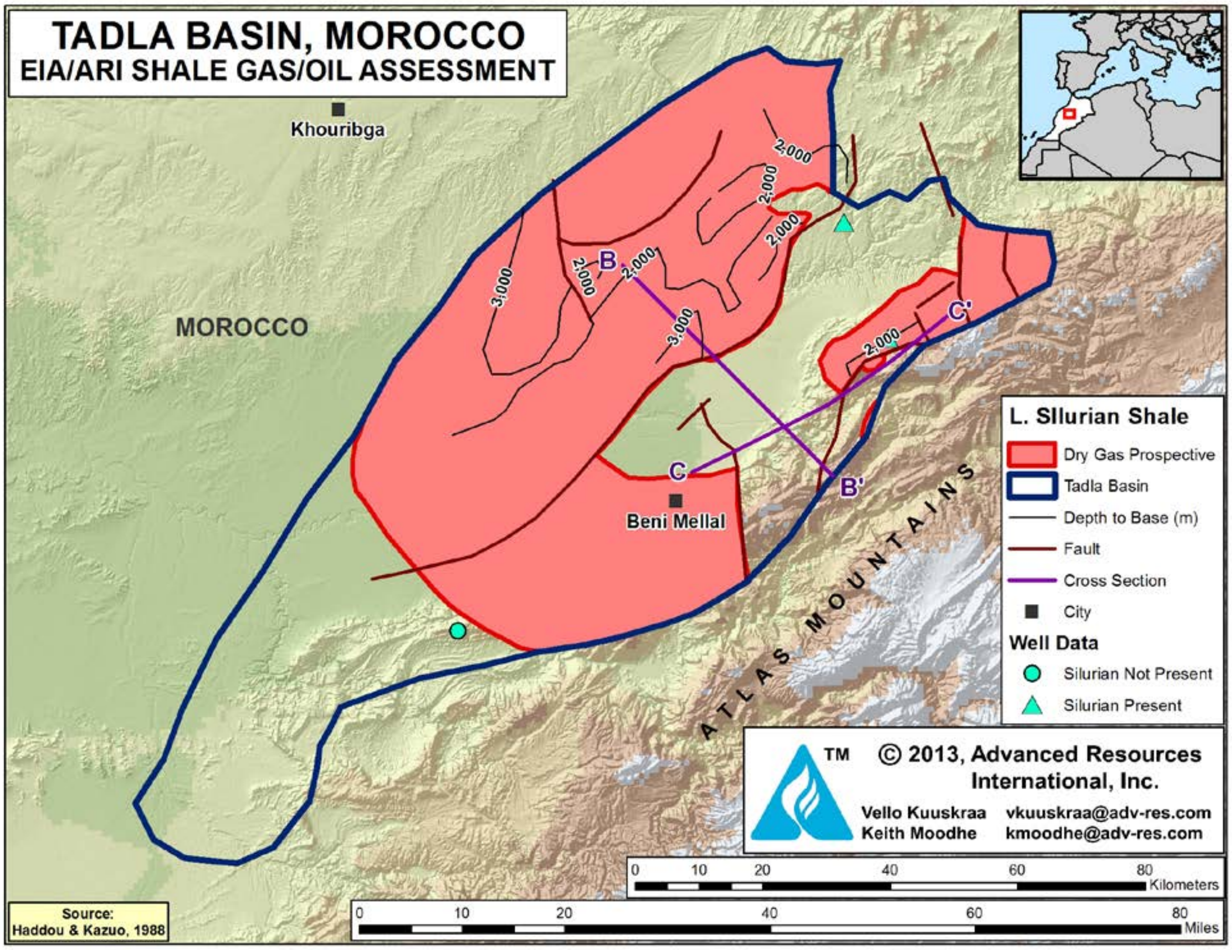


Figure XIV-7. Tadla Basin Cross Sections[8]



Source: Jabour, 1988.

Figure XIV-8. Tadla Basin Prospective Area, Morocco



Source: ARI, 2013

2.3 Resource Assessment

The Silurian “Hot Shale” in the Tadla Basin’s 1,670-mi^2 prospective area has a moderate 49-Bcf/mi^2 dry gas resource concentration. The basin contains an estimated 20 Tcf of risked shale gas in-place, with 3 Tcf as the risked, technically recoverable shale gas resource.

2.4 Recent Activity

No shale gas exploration activity has been reported in the Tadla Basin of Morocco.

3. SHALE RESOURCES BY COUNTRY

3.1 Morocco

Morocco has a 1,670-mi^2 dry gas prospective area in the Tadla Basin and an 8,000-mi^2 dry gas prospective area in the Tindouf Basin. Within these two prospective areas, Morocco has 56 Tcf of risked shale gas in-place, with 12 Tcf as the risked, technically recoverable shale gas resource.

3.2 Western Sahara

The Western Sahara portion of the Tindouf Basin has a 4,380-mi^2 dry gas prospective area, a 4,670-mi^2 wet shale gas/condensate prospective area, and a 2,020-mi^2 shale oil prospective area. Within these prospective areas, Western Sahara has an estimated 39 Tcf of risked dry, wet and associated shale gas in-place, with 8 Tcf as the risked, technically recoverable shale gas resource. In addition, Western Sahara has 5 billion barrels of risked shale oil/condensate in-place, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

3.3 Mauritania

Mauritania has a small 50-mi^2 wet shale gas/condensate prospective area in the Tindouf Basin containing only minor shale gas and oil resources.

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[3] Longreach Petroleum Corporate Presentation, 2010.

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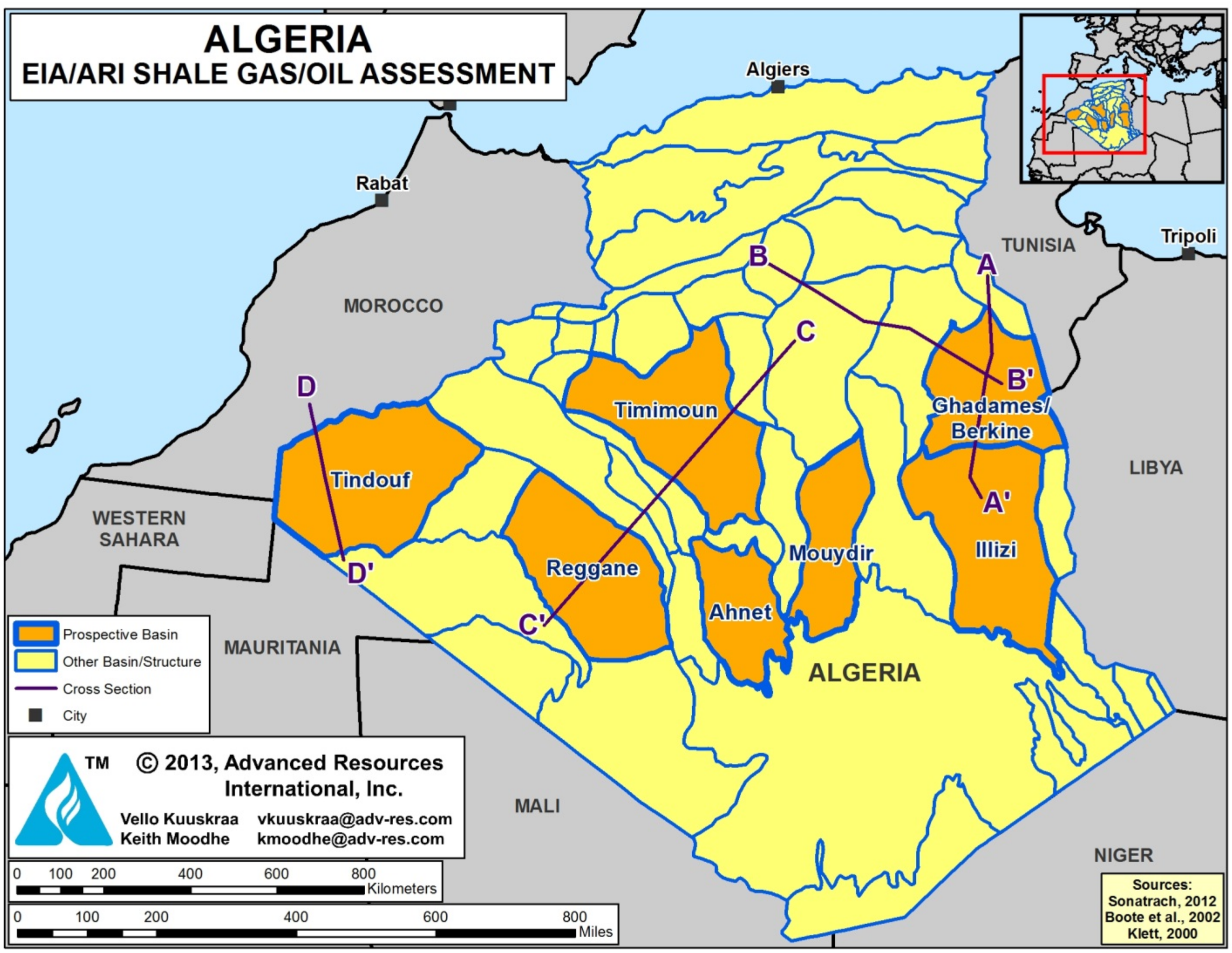
XV. ALGERIA

SUMMARY

Algeria's hydrocarbon basins hold two significant shale gas and shale oil formations, the Silurian Tannezuft Shale and the Devonian Frasnian Shale. This study examines seven of these shale gas and shale oil basins: the Ghadames (Berkine) and Illizi basins in eastern Algeria; the Timimoun, Ahnet and Mouydir basins in central Algeria; and the Reggane and Tindouf basins in southwestern Algeria, Figure XV-1.

Figure XV-1. Shale Gas and Shale Oil Basins of Algeria



Source: ARI, 2013.

Our assessment is that these seven basins contain approximately 3,419 Tcf of risked shale gas in-place, with 707 Tcf as the risked, technically recoverable shale gas resource, Table XV-1A, 1B and 1C. In addition, six of these basins hold 121 billion barrels of risked shale oil and condensate in-place, with 5.7 billion barrels as the risked, technically recoverable shale oil resource, Table XV-2.

Table XV-1A. Shale Gas Reservoir Properties and Resources of Algeria.

Basic Data	Basin/Gross Area		Ghadames/Berkine ($117,000\ mi^2$)					Illizi ($44,900\ mi^2$)	
	Shale Formation		Frasnian			Tannezuft		Tannezuft	
	Geologic Age		U. Devonian			Silurian		Silurian	
	Depositional Environment		Marine			Marine		Marine	
Physical Extent	Prospective Area (mi^2)		2,720	3,840	3,490	6,050	22,080	9,840	16,760
	Thickness (ft)	Organically Rich	275	275	275	115	115	180	180
		Net	248	248	248	104	104	162	162
	Depth (ft)	Interval	8,000 - 10,500	9,000 - 10,000	10,000 - 16,000	10,000 - 14,500	11,000 - 16,000	3,300 - 8,000	3,300 - 8,000
		Average	8,500	9,500	13,000	10,500	13,000	5,000	5,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		6.0%	6.0%	6.0%	5.7%	5.7%	5.7%	5.7%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.70%	1.15%	1.90%	1.15%	1.70%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		35.4	111.4	133.9	42.9	54.5	50.9	60.7
	Risked GIP (Tcf)		48.2	213.8	233.7	129.9	601.3	100.1	203.6
	Risked Recoverable (Tcf)		4.8	42.8	58.4	26.0	150.3	15.0	40.7

Table XV-1B. Shale Gas Reservoir Properties and Resources of Algeria.

Basic Data	Basin/Gross Area		Timimoun ($43,700\ mi^2$)		Ahnet ($20,200\ mi^2$)			Mouydir ($22,300\ mi^2$)
	Shale Formation		Frasnian	Tannezuft	Frasnian		Tannezuft	Tannezuft
	Geologic Age		U. Devonian	Silurian	U. Devonian		Silurian	Silurian
	Depositional Environment		Marine	Marine	Marine		Marine	Marine
Physical Extent	Prospective Area (mi^2)		32,040	41,670	1,650	5,740	11,730	12,840
	Thickness (ft)	Organically Rich	200	100	275	60	330	60
		Net	180	90	248	54	297	54
	Depth (ft)	Interval	3,300 - 9,000	5,000 - 15,000	3,300 - 6,600	5,000 - 9,500	6,000 - 10,500	5,000 - 10,000
		Average	6,000	10,000	5,000	7,000	8,000	6,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		4.0%	2.8%	4.0%	3.0%	2.8%	3.0%
	Thermal Maturity (% Ro)		1.70%	2.00%	1.15%	1.70%	2.00%	2.20%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Dry Gas	Dry Gas	Wet Gas	Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		72.9	35.5	77.6	21.6	109.0	18.5
	Risked GIP (Tcf)		467.1	295.5	25.6	24.8	255.7	47.6
	Risked Recoverable (Tcf)		93.4	59.1	3.8	5.0	51.1	9.5

Advanced Resources International, Inc.

Table XV-1C. Shale Gas Reservoir Properties and Resources of Algeria.

			Reggane (40,000 mi^2)				Tindouf (77,000 mi^2)	
Basic Data	Basin/Gross Area		Reggane (40,000 mi^2)				Tindouf (77,000 mi^2)	
Basic Data	Shale Formation		Frasnian		Tannezuft		Tannezuft	
Basic Data	Geologic Age		U. Devonian		Silurian		Silurian	
Basic Data	Depositional Environment		Marine		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		2,570	2,110	10,150	24,600	5,340	23,800
Physical Extent	Thickness (ft)	Organically Rich	330	260	130	230	60	60
Physical Extent	Thickness (ft)	Net	297	234	117	207	54	54
Physical Extent	Depth (ft)	Interval	5,500 - 14,500	6,600 - 16,000	5,000 - 9,500	7,500 - 16,000	6,600 - 13,000	6,600 - 14,000
Physical Extent	Depth (ft)	Average	10,000	11,000	8,000	12,000	10,000	11,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
Reservoir Properties	Average TOC (wt. %)		3.0%	3.0%	4.0%	4.0%	4.0%	4.0%
Reservoir Properties	Thermal Maturity (% Ro)		1.15%	1.70%	1.15%	1.80%	1.15%	2.50%
Reservoir Properties	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Wet Gas	Dry Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas
Resource	GIP Concentration (Bcf/mi^2)		103.9	97.3	38.3	94.4	18.9	24.2
Resource	Risked GIP (Tcf)		53.4	41.0	77.8	464.5	20.2	115.2
Resource	Risked Recoverable (Tcf)		8.0	8.2	11.7	92.9	3.0	23.0

Table XV-2. Shale Oil Reservoir Properties and Resources of Algeria.

Basic Data	Basin/Gross Area		Ghadames/Berkine (117,000 mi^2)			Illizi (44,900 mi^2)	Ahnet (20,200 mi^2)	Reggane (40,000 mi^2)		Tindouf (77,000 mi^2)
Basic Data	Shale Formation		Frasnian		Tannezuft	Tannezuft	Frasnian	Frasnian	Tannezuft	Tannezuft
Basic Data	Geologic Age		U. Devonian		Silurian	Silurian	U. Devonian	U. Devonian	Silurian	Silurian
Basic Data	Depositional Environment		Marine		Marine	Marine	Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		2,720	3,840	6,050	9,840	1,650	2,570	10,150	5,340
Physical Extent	Thickness (ft)	Organically Rich	275	275	115	180	275	330	130	60
Physical Extent	Thickness (ft)	Net	248	248	104	162	248	297	117	54
Physical Extent	Depth (ft)	Interval	8,000 - 10,500	9,000 - 10,000	10,000 - 14,500	3,300 - 8,000	3,300 - 6,600	5,500 - 14,500	5,000 - 9,500	6,600 - 13,000
Physical Extent	Depth (ft)	Average	8,500	9,500	10,500	5,000	5,000	10,000	8,000	10,000
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
Reservoir Properties	Average TOC (wt. %)		6.0%	6.0%	5.7%	5.7%	4.0%	3.0%	4.0%	4.0%
Reservoir Properties	Thermal Maturity (% Ro)		0.85%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%	1.15%
Reservoir Properties	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate
Resource	OIP Concentration (MMbbl/mi^2)		43.7	9.7	3.1	6.5	14.4	11.4	3.9	1.7
Resource	Risked OIP (B bbl)		59.4	18.7	9.5	12.8	4.8	5.9	8.0	1.8
Resource	Risked Recoverable (B bbl)		2.97	0.93	0.47	0.51	0.19	0.24	0.32	0.07

INTRODUCTION

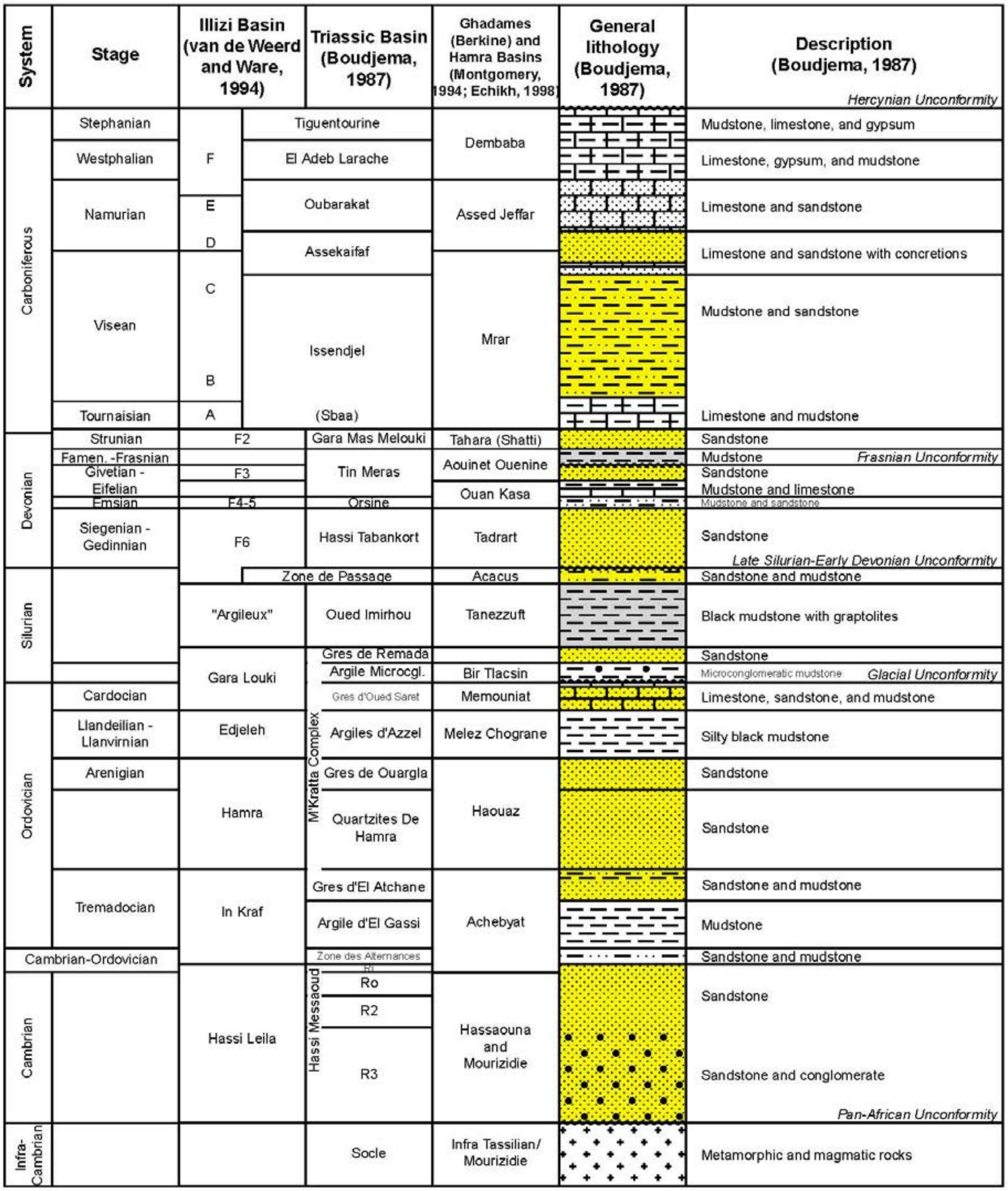
For most of Paleozoic time, North Africa (including Algeria) was a single massive depositional basin.[1] The separation and subsequent collision of Laurasia and Gondwana (the Hercynian event) established the seven individual basin outlines and uplift structures of present day Algeria.[2] Two major transgressions, first in the Silurian and the second in the Late Devonian, provided the deposition of the organically rich marine (generally Type I and II) source rocks in these basins. Subsequent transpressional movements reactivated the older structures. These events, plus additional compression and movement, caused the local uplifts and erosion that today define and characterize these basins.[3]

The stratigraphic column for the shale basins of Algeria is provided in Figure XV-2,[4] identifying the Silurian Tannezuft black mudstone interval and the Upper Devonian Frasnian mudstone that are the principal shale source rocks for the conventional oil and gas discovered to date in Algeria. The stratigraphy of the Silurian section is generally more continuous than of the Devonian section, which has been influenced by more localized deposition[5].

Geochemical modeling indicates that these shales may have generated over 26,000 Tcf of gas (including secondary cracking of generated oil), with some portion of this gas still retained in the shales. The present day total organic content (TOC) of the Silurian Tannezuft Shale ranges from 2% to 4%. However, the TOC of the shale has been reduced by as much as one-half due to the thermal maturation process.[6] The present day TOC of the Upper Devonian Frasnian Shale ranges more widely, from 1% to 8%, decreasing westward across the region.

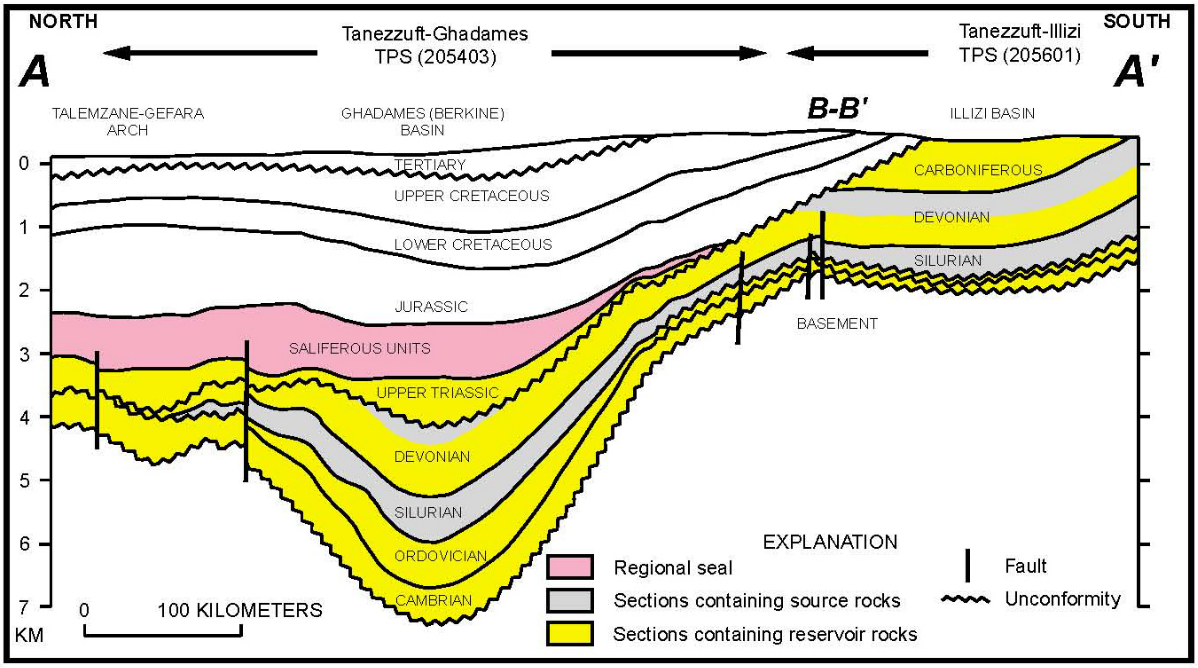
The following series of three regional cross-sections provides a useful perspective of the depositional and structural setting for six of these basins, Figures XV-3,[4] XV-4[4] and XV-5.[1] Figure XV-1(provided previously) shows the location of these three cross-sections.

Figure XV-2. Stratigraphic Column and Nomenclature for Illizi and Ghadames (Berkine) Basins.
(Major reservoir rocks are shown in yellow and source rocks in gray.)



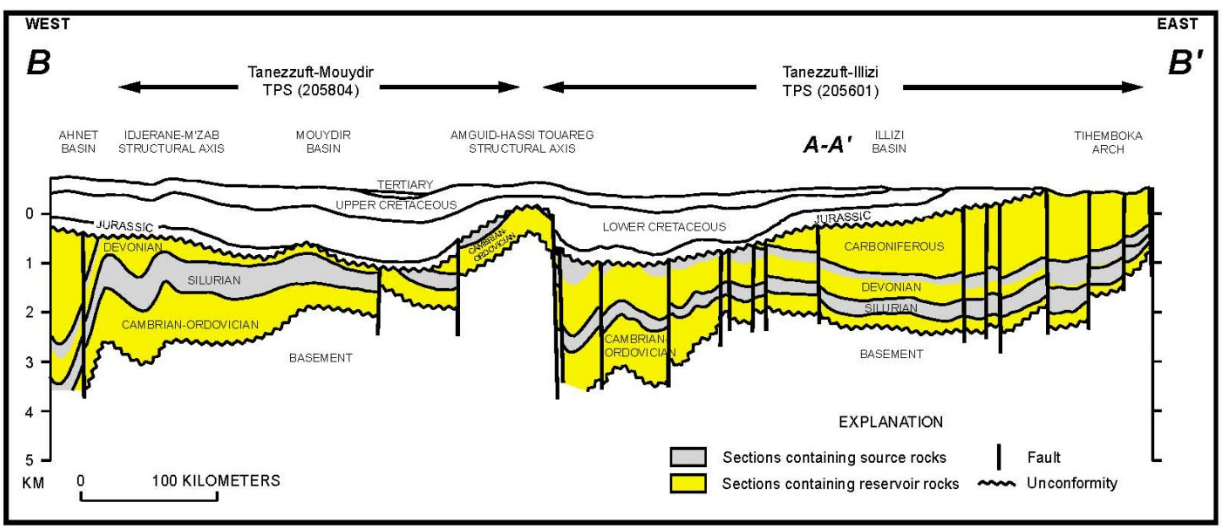
Source: Klett, 2000A.

Figure XV-3. Cross Section A-A': Ghadames (Berkline) and Illizi Basins



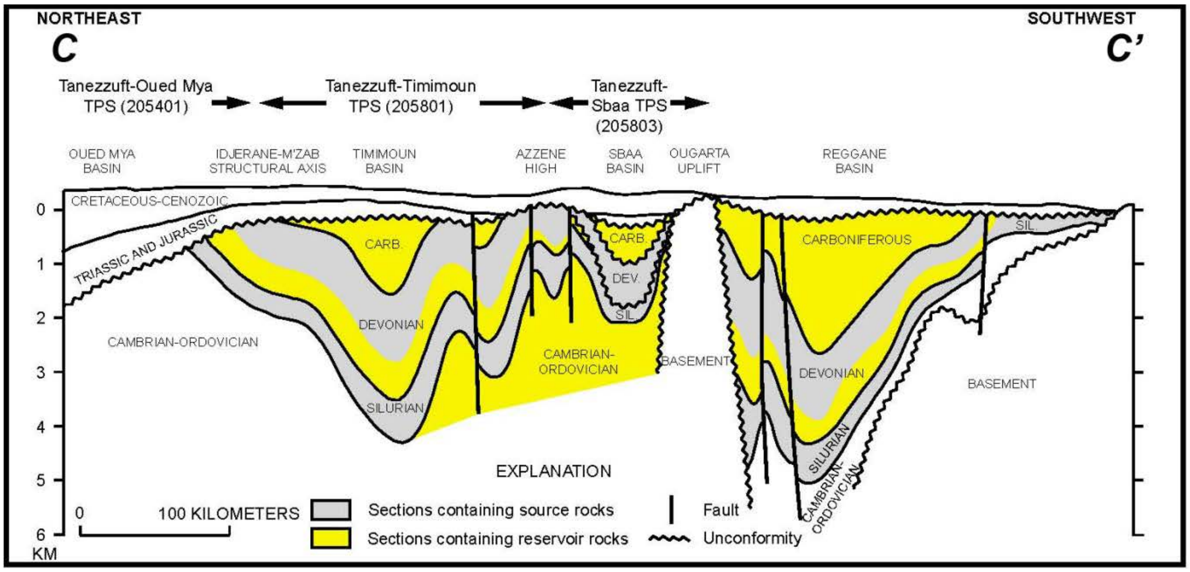
Source: Klett, 2000A.

Figure XV-4. Cross Section B-B': Ahnet, Mouydir and Illizi Basins



Source: Klett, 2000A.

Figure XV-5. Cross-Section C-C': Timimoun and Reggane Basins



Source: Klett, 2000B.

1. GHADAMES (BERKINE) BASIN

1.1 Geologic Setting

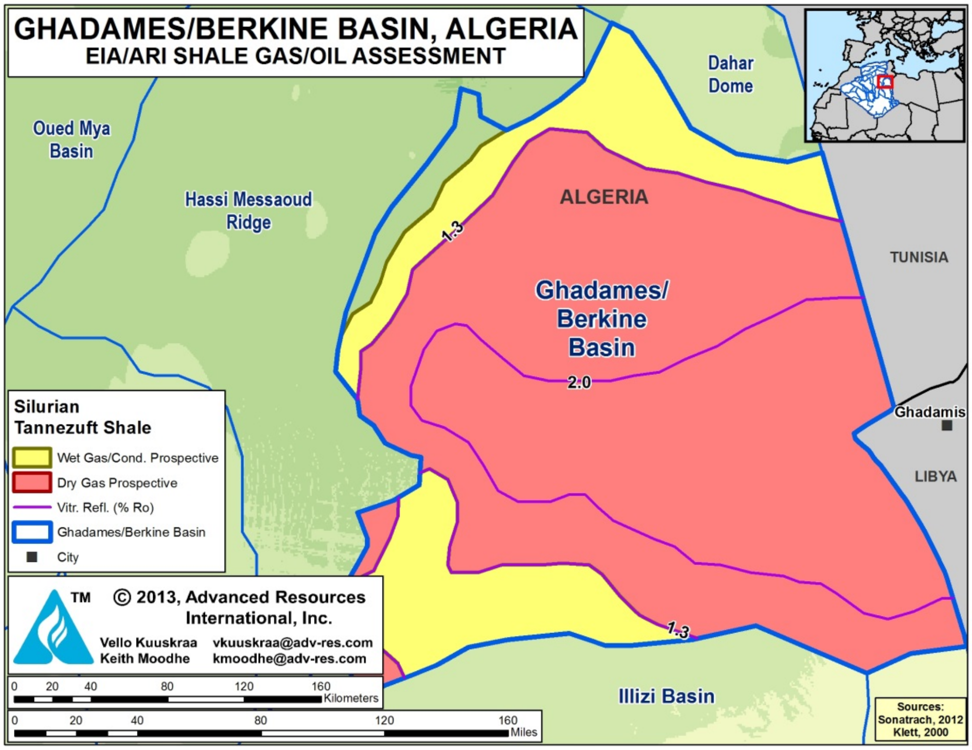
The Ghadames (Berkine) Basin is a large intra-cratonic basin underlying eastern Algeria, southern Tunisia and western Libya. The basin contains a series of reverse faults, providing structural traps for conventional oil and gas sourced from Devonian- and Silurian-age shales. The central, deep portion of the basin contains uplifted fault blocks formed during the Cambrian-Ordovician.[7] The Ghadames Basin and its two significant shale formations, the Silurian Tannezuft and the Upper Devonian Frasnian, are located in the eastern portion of Algeria. Figures XV-6 and XV-7 provide the basin outline and shale thermal maturity contours for these two shale formations.

In Algeria's portion of the Ghadames Basin, the Silurian Tannezuft Formation contains an organic-rich marine shale that increases in maturity toward the basin center. We have mapped a 28,130-mi^2 higher quality prospective area for the Tannezuft Shale in this basin. The western and northern boundaries of the Tannezuft Shale prospective area are defined by the erosional limits of the Silurian and by minimum thermal maturity. The eastern border of the prospective area is defined by the Tunisia and Algerian border.

The central, dry gas portion of the Tannezuft Shale prospective area in the Ghadames Basin, covering 21,420 mi^2, has thermal maturity (R_o) of 1.3% to over 2%. The remaining portion of the prospective area of 6,710 mi^2 has an R_o between 1.0% and 1.3%, placing this area in the wet gas and condensate window.

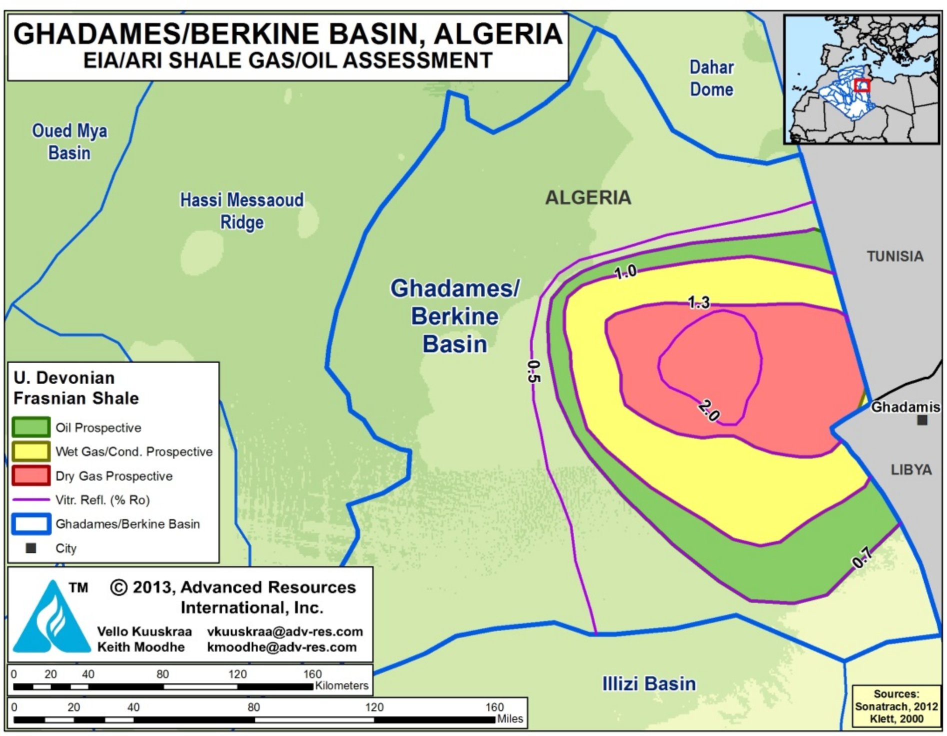
Deposited above the Tannezuft is the areally more limited and thermally less mature Upper Devonian Frasnian Shale. We have mapped a 10,040-mi^2 higher quality prospective area for the Frasnian Shale in the Ghadames Basin of Algeria. The western, northern and southern boundaries of the Frasnian Shale prospective area are set by the minimum thermal maturity criterion of 0.7% R_o. The eastern boundary of the prospective area is the Tunisia and Algeria border. The northern, eastern and southern outer ring of the Frasnian Shale prospective area in the Ghadames Basin, encompassing an area of 2,720 mi^2, is in the oil window with R_o between 0.7% and 1.0%. The central 5,010-mi^2 portion of the Frasnian Shale prospective area is in the dry gas window, with R_o of 1.3% to over 2%. In between is the 2,310-mi^2 wet gas and condensate window for the Frasnian Shale, with R_o between 1.0% and 1.3%.

Figure XV-6. Ghadames Basin Silurian Tannezuft Shale Outline and Thermal Maturity



Source: ARI, 2013.

Figure XV-7. Ghadames Basin Upper Devonian Frasnian Shale Outline and Thermal Maturity



Source: ARI, 2013.

1.2 Reservoir Properties (Prospective Area)

Silurian Tannezuft Formation. The depth of the gas prospective area of the Silurian Tannezuft Shale in the Ghadames (Berkine) Basin of Algeria ranges from 10,000 ft along the northern and eastern edge of the basin to 16,000 ft in the basin center, averaging 10,500 ft in the wet gas prospective area and 13,000 ft in the dry gas prospective area. The gross thickness of the Tannezuft Shale ranges from 30 to 200 ft, with an organic-rich average net thickness of 104 ft. The TOC of the Tannezuft Shale averages 5.7%. The lower portion of the formation is particularly organic-rich, with TOC values of up to 15%.[8]

Upper Devonian Frasnian Formation. The depth of the prospective area of the overlying Upper Devonian Frasnian Shale ranges from 8,000 ft to 16,000 ft, averaging 8,500 ft in the oil-prone area, 9,500 ft in the wet gas/condensate area, and 13,000 ft in the dry gas area. The Frasnian Shale has a gross thickness of 50 to 500 ft, with an average organic-rich net thickness of 248 ft. The Frasnian Shale has TOC values ranging from 3% to 10%, with an average of 6%.[10]

1.3 Resource Assessments

Silurian Tannezuft Shale. The Tannezuft Shale, within its 6,050-mi^2 wet gas and condensate prospective area, has resource concentrations of 43 Bcf/mi^2 of wet gas and 3 million barrels/mi^2 of condensate. Within its larger 22,080-mi^2 dry gas prospective area, the Tannezuft Shale has a resource concentration of 55 Bcf/mi^2. The risked resource in-place for the 28,130-mi^2 wet gas/condensate and dry gas prospective areas of the Tannezuft Shale is 731 Tcf of wet and dry gas and 10 billion barrels of condensate. Based on presence of clays but otherwise favorable reservoir properties, we estimate a risked, technically recoverable resource of 176 Tcf of wet/dry shale gas and 0.5 billion barrels of shale condensate.

Upper Devonian Frasnian Shale. The Frasnian Shale has resource concentrations of 44 million barrels/mi^2 for oil in the 2,720-mi^2 oil window; 10 million barrels/mi^2 of condensate and 111 Bcf/mi^2 of wet gas in the 3,840-mi^2 wet gas/condensate window; and 134 Bcf/mi^2 of dry gas in the 3,490-mi^2 dry gas window. The risked resource in-place within the overall 10,050-mi^2 prospective area is 496 Tcf of shale gas and 78 billion barrels of shale oil/condensate, with risked, recoverable of 106 Tcf for shale gas and 3.9 billion barrels for shale oil.

2. ILLIZI BASIN

2.1 Geologic Setting

The Illizi Basin is located south of the Ghadames (Berkine) Basin, separated by a hinge line in the slope of the basement rocks. This hinge line controls much of the differing petroleum generation, migration and accumulation histories of these two basins.[4] The Illizi Basin is bounded on the east by the Tihemboka (Garoaf) Arch, on the south by the Hoggar Massif, and on the west by the Amguid-Hassi Touareg structural axis which separates the Illizi Basin from the Mouydir Basin, Figure XV-8.[4] The Illizi Basin is located on a basement high and thus its shale formations are shallower than in the Ghadames (Berkline) Basin. We have mapped an overall shale gas and oil prospective area of 26,600 mi^2 for the Illizi Basin.

2.2 Reservoir Properties (Prospective Area)

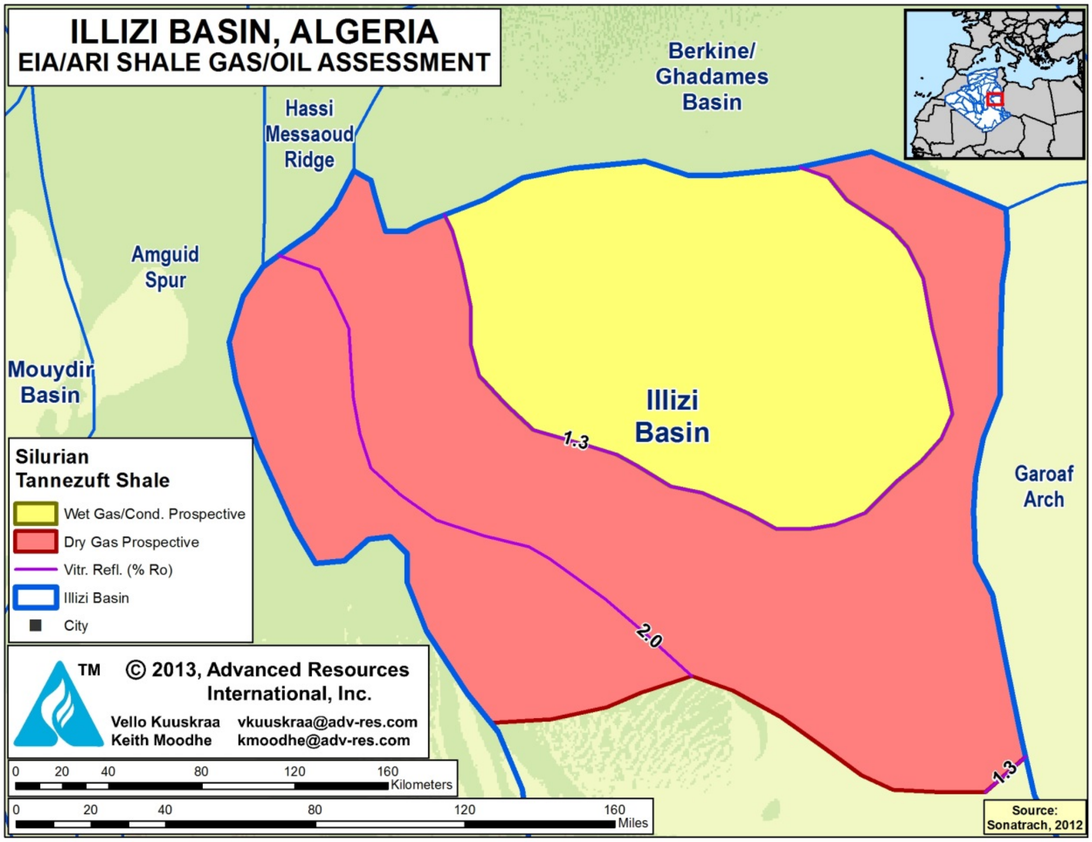
Only the Silurian Tannezuft Shale is assessed as prospective in the Illizi Basin. (The Upper Devonian Frasnian Shale in the Illizi Basin has been excluded because of insufficient thickness and low thermal maturity.) The depth of the Tannezuft Shale ranges from 3,000 to 8,000 ft, averaging 5,000 ft in the northern prospective area of the basin. The gross thickness of the Tannezuft Shale ranges from 30 to 330 ft, with an average net pay of 162 ft. The TOC of this Type II kerogen marine shale ranges from 2% to 10%, with an average of 5.7%. The basin has a thermal maturity (R_o) of 1% to over 2%. This places the Tannezuft Shale in the wet gas and condensate window (R_o of 1% to 1.3%) in the north-central portion of the basin and places the shale in the deeper surrounding area of the Illizi Basin in the dry gas window.

2.3 Resource Assessment

Within its 9,840-mi^2 prospective area for wet gas and condensate, the Silurian Tannezuft Shale of the Illizi Basin has resource concentrations of 51 Bcf/mi^2 of wet shale gas and 6 million barrels/mi^2 of shale oil and condensate. Within its 16,760-mi^2 prospective area for dry gas, the shale has a resource concentration of 61 Bcf/mi^2.

The risked resource in-place in the total prospective area is estimated at 304 Tcf of wet/dry shale gas plus 13 billion barrels of shale oil/condensate. Of this, 56 Tcf of wet/dry shale gas and 0.5 billion barrels of shale oil/condensate are estimated as the risked, technically recoverable resource.

Figure XV-8. Illizi Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



Source: ARI, 2013.

3. TIMIMOUN BASIN

3.1 Geologic Setting

The Timimoun Basin, located in central Algeria, is bounded on the north and east by structural uplifts, on the west by the Beni Abbes Saddle, and on the south by the Djoua Saddle that separates the Timimoun Basin from the Ahnet Basin. The depth and deposition of the Timimoun Basin varies greatly due to erosion along the structural highs during the Hercynian. The Paleozoic section is thickest in the center of the Timimoun Basin, thinning to the north and east. The major shale source rocks in this basin are the Silurian Tannezuft Shale and the Upper Devonian Frasnian Shale.

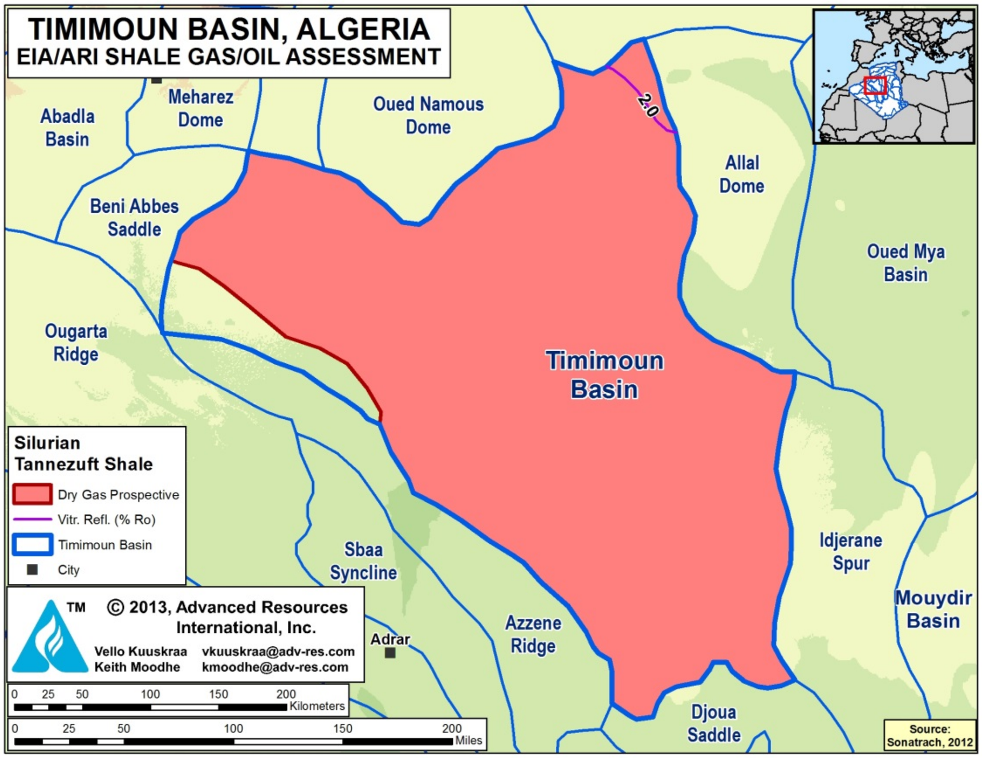
We mapped a 41,670-mi^2 dry gas prospective area for the Tannezuft Shale that covers essentially all of the Timimoun Basin, excluding a small area along the north-western portion of the basin where the Silurian is absent, Figure XV-9. In addition, we mapped a 32,040-mi^2 Frasnian Shale dry gas prospective area that covers the eastern two-thirds of the basin, excluding the low (<2%) TOC area along the western portion of the basin, Figure XV-10.

3.2 Reservoir Properties (Prospective Area).

Silurian Tannezuft Formation. The depth of the dry gas prospective area of the Tannezuft Shale in the Timimoun Basin ranges from 5,000 ft on the edges of the basin to nearly 15,000 ft in the basin center, averaging 10,000 ft. The thickness of the gross shale interval is 100 ft, with a net organic-rich pay of 90 ft. The TOC of the Tannezuft Shale averages 2.8% in the prospective area.

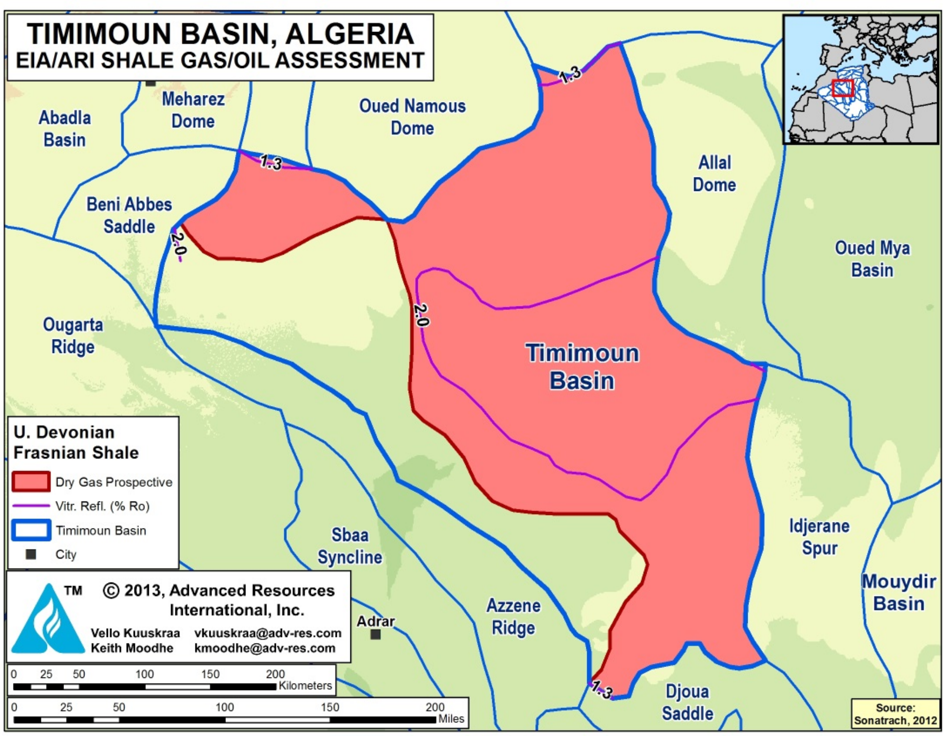
Upper Devonian Frasnian Formation. The depth of the dry gas prospective area of the Upper Devonian Frasnian Shale in the Timimoun Basin ranges from about 3,300 ft along the basin edge to about 9,000 ft in the basin center, averaging 6,000 ft. The thickness of the gross shale interval is 200 ft, with a net organic-rich pay of 180 ft. The TOC of the Frasnian Shale averages 4% in the prospective area.

Figure XV-9. Timimoun Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



Source: ARI, 2013.

Figure XV-10. Timimoun Basin Upper Devonian Frasnian Shale, Outline and Thermal Maturity



Source: ARI, 2013.

Advanced Resources International, Inc.

3.3 Resource Assessment

Silurian Tannezuft Shale. The Tannezuft Shale, within the 41,670-mi^2 dry gas prospective area of the Timimoun Basin, has a resource concentration of 36 Bcf/mi^2. The risked shale gas resource in-place in the prospective area is 296 Tcf, with 59 Tcf as the risked, technically recoverable shale gas resource.

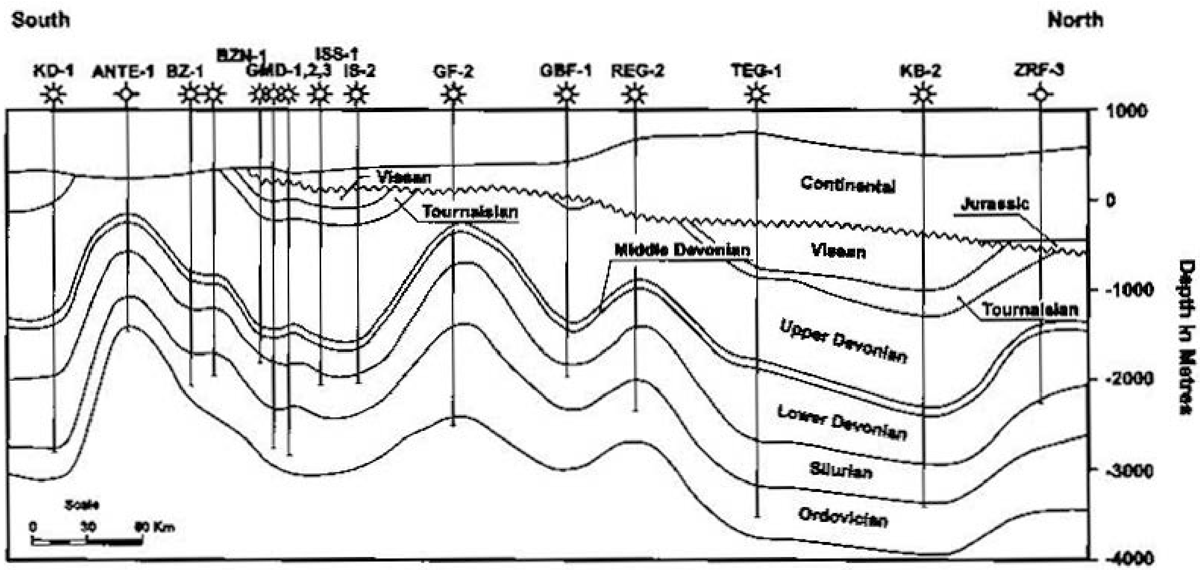
Upper Devonian Frasnian Shale. The Frasnian Shale, within the 32,040-mi^2 dry gas prospective area of the Timimoun Basin, has a resource concentration of 73 Bcf/mi^2. The risked shale gas resource in-place in the prospective area is 467 Tcf, with 93 Tcf as the risked, technically recoverable shale gas resource.

4. AHNET BASIN

4.1 Geologic Setting

The Ahnet Basin is located in the Sahara Desert Platform, south of the large Timimoun Basin, west of the Mouydir Basin, and north of the Hoggar Shield. The Ahnet Basin is a north-south trending basin that contains thick (over 3,000 ft) of Paleozoic sediments including organic-rich Silurian and Devonian shales. The structures in the basin take the form of large, elongate anticlines and domes formed as a result of tectonic compression, as shown on the north to south cross-section, Figure XV-11.[9]

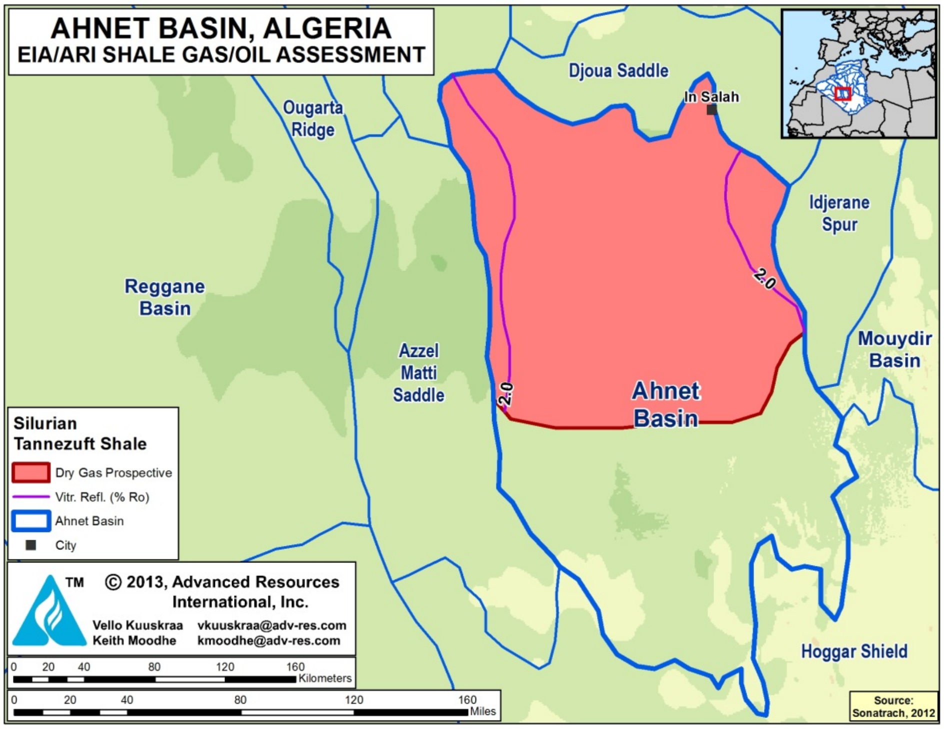
Figure XV-11. Schematic Cross Section of the Ahnet Basin, Algeria



Source: Logan, P. and Duddy, I., 1998.

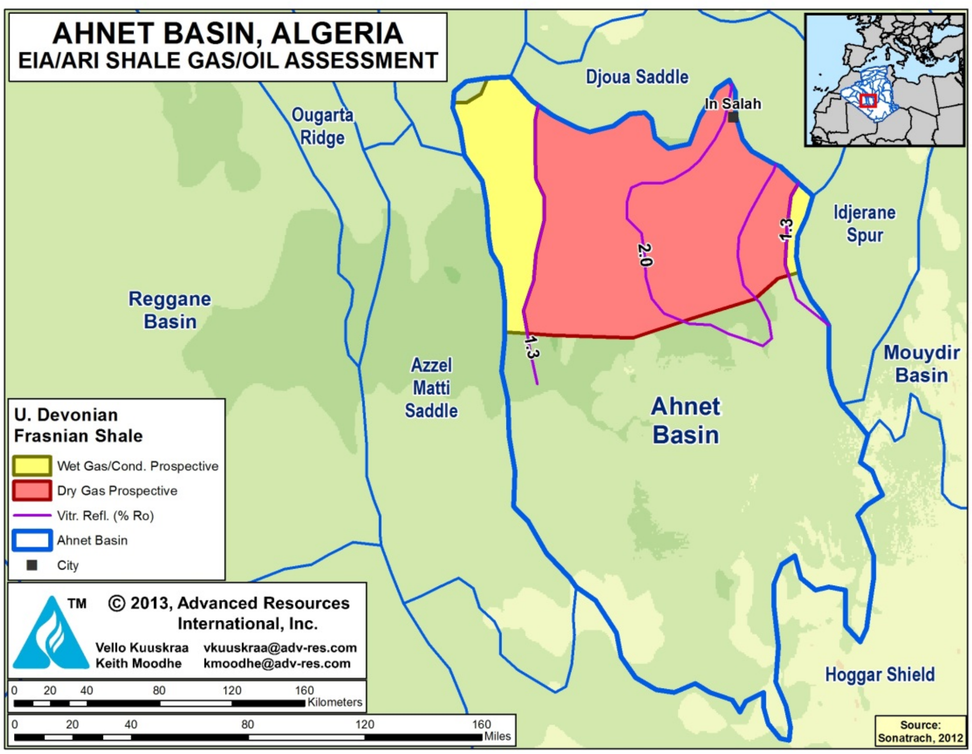
The Ahnet Basin contains the Silurian Tannezuft and Upper Devonian Frasnian formations and their organic-rich shale intervals. In some portions of the basin, the Paleozoic section was eroded during Hercynian deformation. However, up to 4 km of Paleozoic deposits remain intact in the center of the basin.[9] We have defined prospective areas of 11,730 mi^2 for the Silurian Tannezuft Shale and 7,390 mi^2 for the Devonian Frasnian Shale in the northern portion of the Ahnet Basin, Figures XV-12 and XV-13.

Figure XV-12. Ahnet Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



Source: ARI, 2013.

Figure XV-13. Ahnet Basin Upper Devonian Frasnian Shale, Outline and Thermal Maturity



Source: ARI, 2013.

4.2 Reservoir Properties (Prospective Area).

Silurian Tannezuft Formation. The depth of the Tannezuft Shale in the prospective area of the Ahnet Basin ranges from 6,000 to 10,500 ft, averaging 8,000 ft. The thickness of the shale ranges from 150 to 500 ft, averaging 330 ft with a high net to gross ratio. The TOC of the shale ranges from 1.5% to 4% and contains Type III gas-prone kerogen. The thermal maturity places the prospective area of the Tannezuft Shale of the Ahnet Basin in the dry gas window (R_o > 1.3%).

Devonian Frasnian Formation. The depth of the Frasnian Shale in the prospective area of the Ahnet Basin ranges from about 3,300 to 9,500 ft, averaging 6,000 ft, with the wet gas/condensate area shallower and the dry gas area deeper. The gross thickness of the shale ranges from 60 to 275 ft, with a net pay of approximately 54 ft in the dry gas area and 248 ft in the wet gas/condensate area. The TOC ranges from 3% to 4% and is mostly Type III gas-prone kerogen. The thermal maturity of the prospective area of the Frasnian Shale is in the wet gas/condensate and dry gas windows (R_o > 1.0%). Petrophysical evaluations of the Frasnian Shale indicate porosity of 6% and low water saturation in the deeper, prospective area of the Ahnet Basin.

4.3 Resource Assessments (Prospective Area).

Silurian Tannezuft Shale. Within its 11,730-mi^2 dry gas prospective area, the Tannezuft Shale in the Ahnet Basin has a resource concentration of 109 Bcf/mi^2. The risked shale gas resource in-place in the dry gas prospective area is 256 Tcf, with 51 Tcf estimated as the risked, technically recoverable shale gas resource.

Devonian Frasnian Shale. Within its 5,740-mi^2 dry gas prospective area, the Frasnian Shale in the Ahnet Basin has a resource concentration of 22 Bcf/mi^2. Within its 1,650-mi^2 wet gas/condensate prospective area, the Frasnian Shale has resource concentrations of 15 million barrels/mi^2 of shale oil/condensate and 78 Bcf/mi^2 of wet shale gas.

The risked shale gas resource in-place in the overall 7,390-mi^2 wet/dry gas prospective area is 50 Tcf, with 9 Tcf as the risked technically recoverable shale gas resource. The risked shale oil resource in-place in the 1,650-mi^2 oil/condensate prospective area is 5 billion barrels, with 0.2 billion barrels as the risked, technically recoverable shale oil resource.

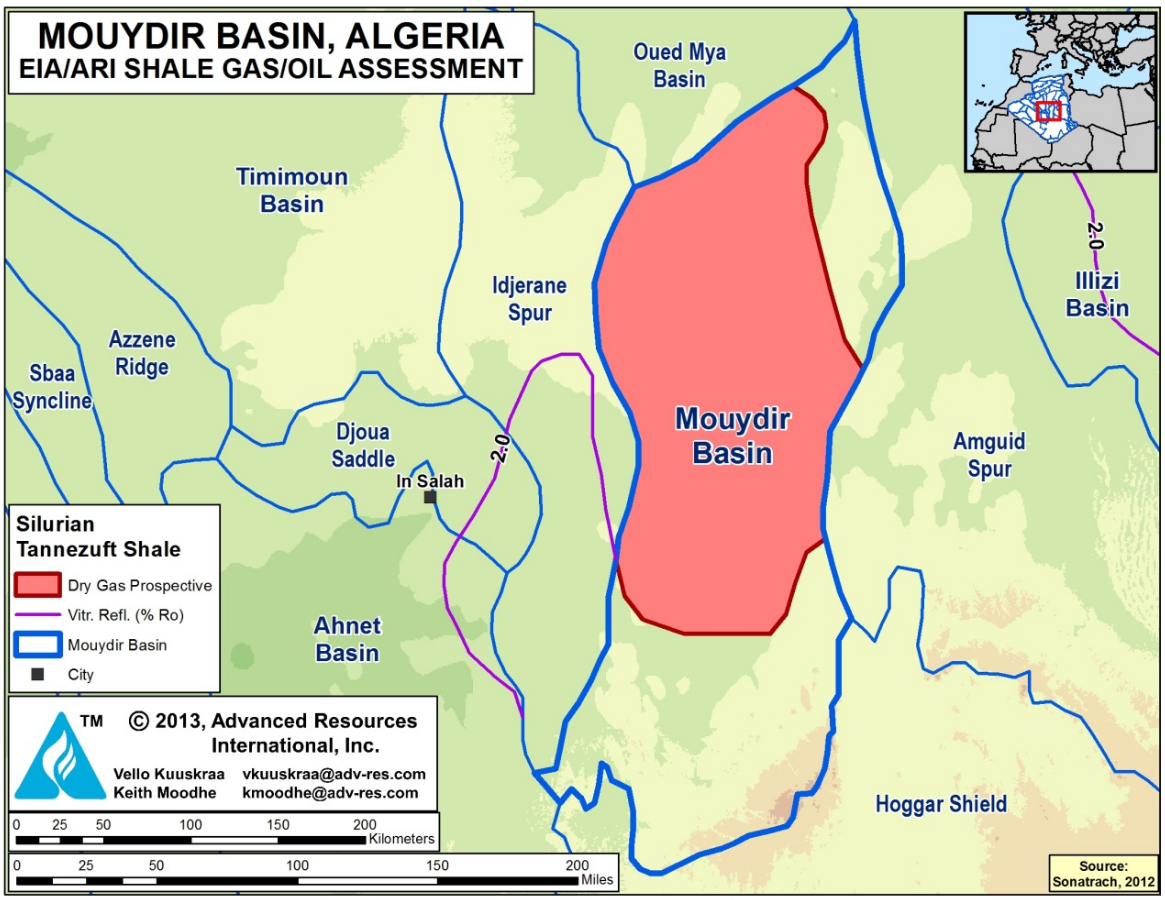
5. MOUYDIR BASIN

5.1 Geologic Setting.

The Mouydir Basin is located in central Algeria, west of the Illizi Basin and east of the Timimoun and Ahnet basins. A variety of upthrusted structural ridges separate these basins. The Paleozoic Silurian and Devonian sediments, which include the important Silurian Tannezuft Shale and the Upper Devonian Frasnian Shale, are deepest in the northern portion of the basin and crop out in the southern portion of the basin.

We have mapped a prospective area of 12,840 mi^2 in the northern portion of the basin, limited on the south by the depth of the shale, Figure XV-14.

Figure XV-14. Mouydir Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



Source: ARI, 2013.

5.2 Reservoir Properties (Prospective Area).

Only the Silurian Tannezuft Shale is assessed as prospective in the Mouydir Basin. (The Devonian Frasnian Shale, although thick and organically rich, is mostly too shallow, less than 3,300 ft, excluding the shale from further assessment.) The depth of the Tannezuft Shale ranges from 5,000 to 10,000 ft, averaging 6,500 ft in the prospective area. The gross thickness of the shale ranges from 20 to 120 ft, averaging 60 ft with a high net to gross ratio. The Tannezuft Shale in the Mouydir Basin has TOC ranging from 2% to 4%, with a thermal maturity above 1.3% R_o, placing the shale in the dry gas window.

5.3 Resource Assessment.

Within its 12,840-mi^2 dry gas prospective area, the Silurian Tannezuft Shale of the Mouydir Basin has a resource concentration of 19 Bcf/mi^2. The risked resource in-place in the dry gas prospective area is estimated at 48 Tcf, with 10 Tcf as the risked, technically recoverable shale gas resource.

6. REGGANE BASIN

6.1 Geologic Setting.

The Reggane Basin, located in the Sahara Desert portion of central Algeria, is separated from the Timimoun Basin by the Ougarta Ridge. The basin is an asymmetric syncline, bounded on the north by a series of reserve faults and on the south by shallowing outcrops, Figure XV-15.[9] This basin may contain over 800 m of Silurian section, although well control in the deep northern portion of the basin is limited. The basin also contains the Upper Devonian Frasnian Formation which is reported to reach a maximum thickness of 400 m.

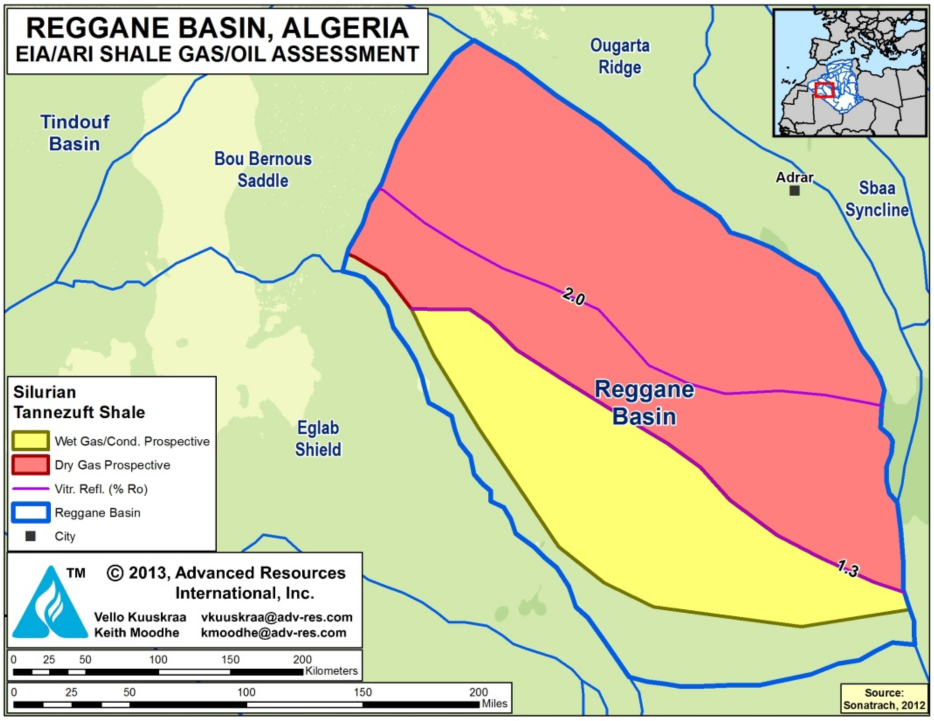
We have mapped prospective areas of 34,750 mi^2 for the Silurian Tannezuft Shale and 4,680 mi^2 for the Upper Devonian Frasnian Shale in the eastern portions of the Reggane Basin, Figures XV-16 and XV-17.

6.2 Reservoir Properties (Prospective Areas).

Silurian Tannezuft Formation. The depth of the prospective area for the Silurian Tannezuft Shale ranges from 16,000 ft on the north to 5,000 ft on the south, averaging 10,000 ft. The wet gas/condensate prospective area is slightly shallower than this average, while the dry gas prospective area is deeper.[9] The gross thickness of the organic-rich section in the prospective area ranges from about 130 to 230 ft, with a high net to gross ratio.[9] TOC is favorable, ranging from 3% to 5%. The thermal maturity places the prospective area of the Tannezuft Shale into the wet gas and condensate window (R_o of 1.0 to 1.3%) in the shallower south and into the dry gas window (R_o > 1.3%) in the deeper north, as illustrated by the north to south cross-section on Figure XV-17.[10]

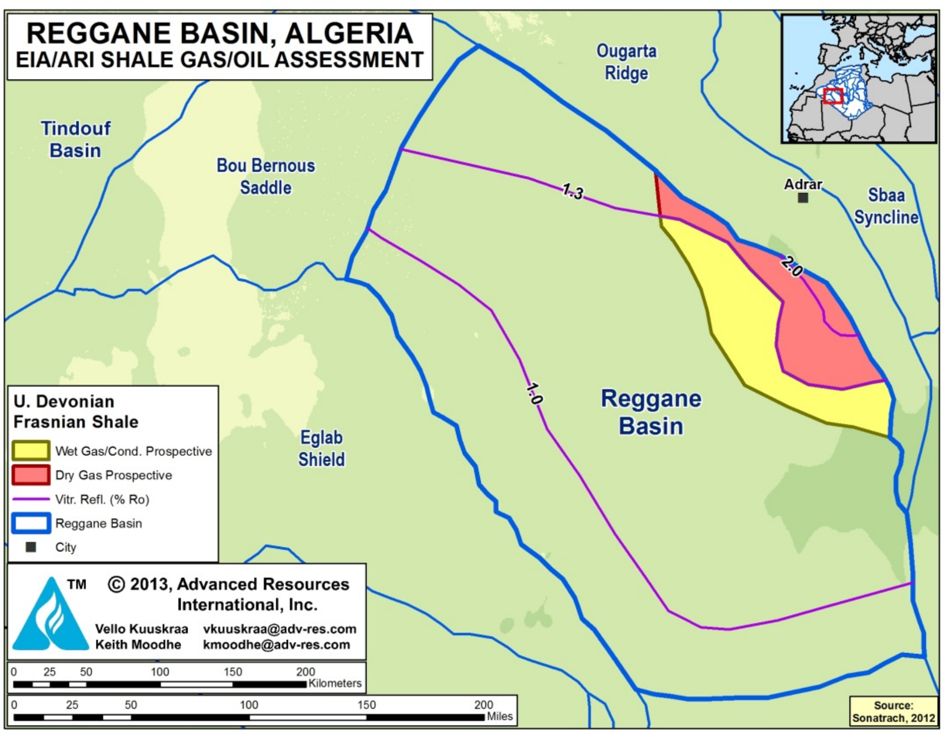
Upper Devonian Frasnian Formation. The depth of the shallower Upper Devonian Frasnian Shale in the Reggane Basin ranges from 5,500 ft to 16,000 ft, averaging about 10,500 ft in the prospective area, with the wet gas/condensate area shallower and the dry gas area somewhat deeper.[9] The thickness of the organic-rich portion of the shale ranges from 260 to 330 ft, with a high net to gross ratio.[9] The TOC of the shale ranges from 2% to 4%.[10] The thermal maturity places the prospective area of the Frasnian Shale in the wet/condensate and dry gas windows (R_o > 1%). The Frasnian Shale is judged to have good porosity of about 6% with low water saturation, based on petrophysical evaluations of the Frasnian Shale in the adjoining Ahnet Basin.[10,11]

Figure XV-15. Reggane Basin Silurian Tannezuft Shale, Outline and Thermal Maturity



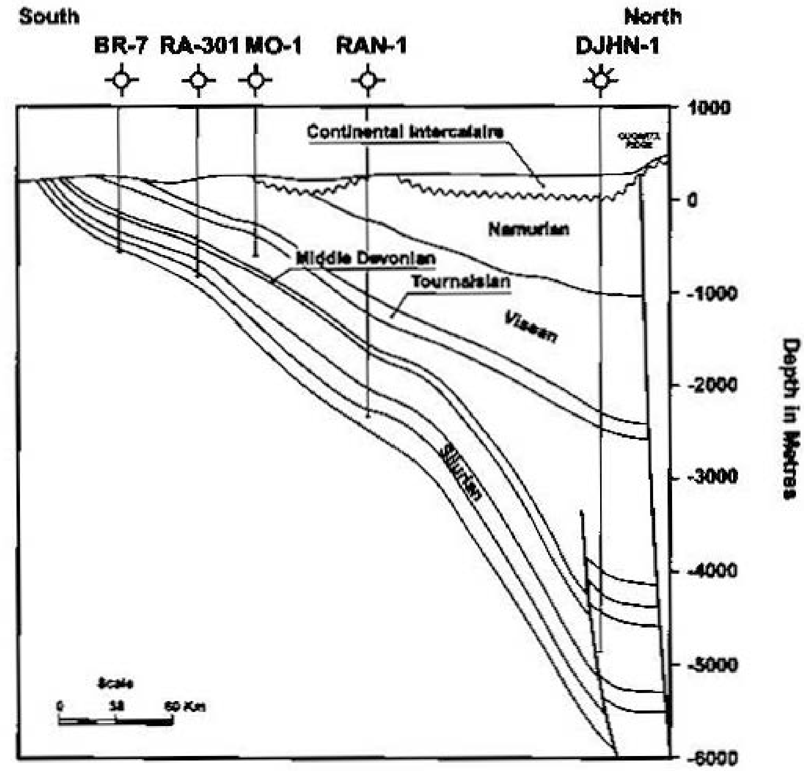
Source: ARI, 2013.

Figure XV-16. Reggane Basin Upper Devonian Frasnian Shale, Outline and Thermal Maturity



Source: ARI, 2013.

Figure XV-17. Schematic Cross Section of the Reggane Basin, Algeria



Source: Logan, P. and Duddy, I., 1998.

6.3 Resource Assessment

***Silurian Tannezuft Shale*.** Within its 24,600-mi^2 dry gas prospective area, the Tannezuft Shale in the Reggane Basin has a resource concentration of 94 Bcf/mi^2. Within its 10,150-mi^2 wet gas and condensate prospective area, the shale has resource concentrations of 38 Bcf/mi^2 of wet gas and 4 million barrels/mi^2 of oil/condensate.

The risked resource in-place for the overall 34,750-mi^2 Silurian Tannezuft Shale prospective area in the Reggane Basin is 542 Tcf of wet/dry shale gas plus 8 billion barrels of shale oil/condensate. Of this, 105 Tcf of wet/dry shale gas plus 0.3 billion barrels of shale oil/condensate are estimated as the risked, technically recoverable resource.

Devonian Frasnian Shale. Within its 2,110-mi^2 dry gas prospective area, the Frasnian Shale in the Reggane Basin has a resource concentration of 97 Bcf/mi^2. Within its 2,570-mi^2 wet gas and condensate prospective area, the shale has resource concentrations of 104 Bcf/mi^2 of wet gas and 11 million barrels/mi^2 of oil and condensate.

The risked resource in-place for the overall 4,680-mi^2 Devonian Frasnian Shale prospective area in the Reggane Basin is estimated at 94 Tcf of wet/dry shale gas plus 6 billion barrels of shale oil/condensate. Of this, 16 Tcf of wet/dry shale gas plus 0.2 billion barrels of shale oil/condensate are estimated as the risked, technically recoverable resource.

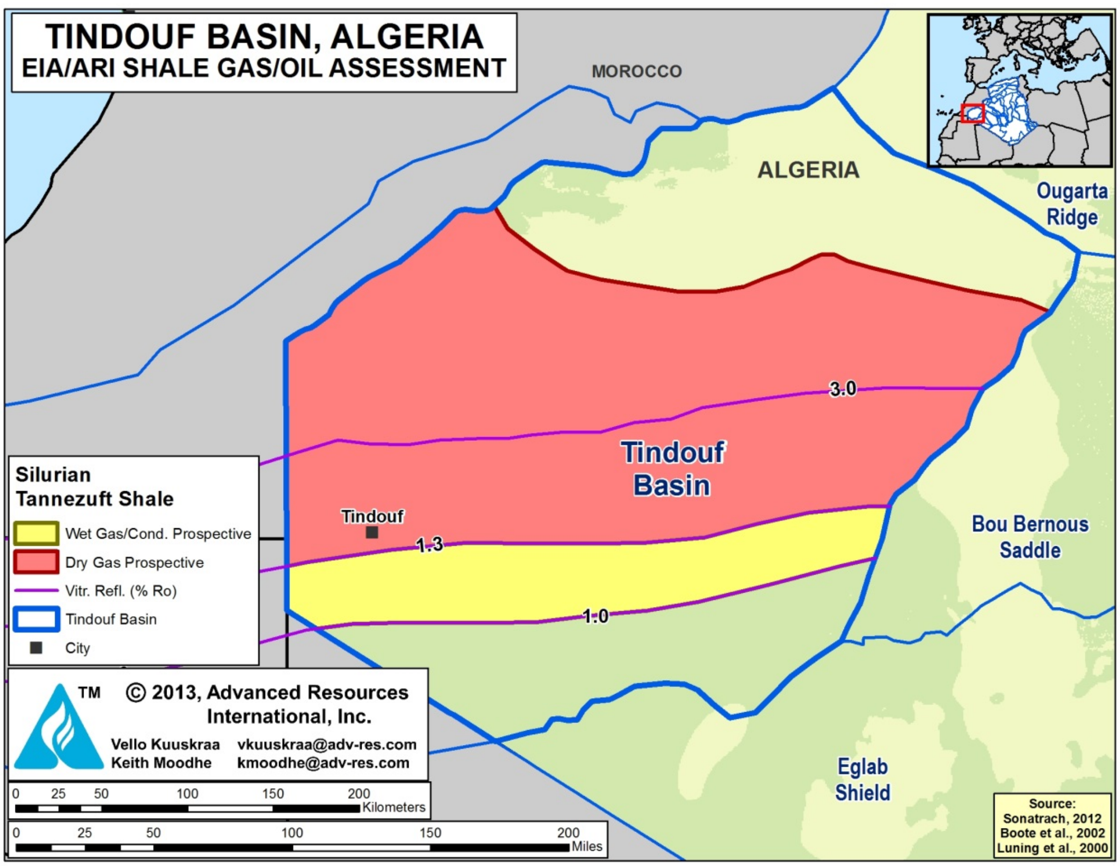
7. TINDOUF BASIN

7.1 Geological Setting.

The Tindouf Basin is located in the far southwestern portion of Algeria, bordered on the west by Morocco and on the south by Mauritania. This large basin, the least explored basin in the Sahara Desert Platform, covers an area of over 45,000 mi^2 just within the Algeria.

Because of limited well penetrations, considerable uncertainty surrounds the shale gas and oil potential of the Tindouf Basin. Based on recent data from Sonatrach, the Devonian Frasnian Shale is relatively thin (average of 10 m) with a TOC of only about 1%.[10] As such, this shale unit has been excluded from further quantitative assessment. However, the Silurian Tannezuft Shale appears to be more promising. We have established a dry and wet gas prospective area of 29,140 mi^2 for the Silurian Tannezuft Shale in the northern portion of the Tindouf Basin where the TOC is 2% or higher, Figure XV-18.

Figure XV-18. Tindouf Basin Silurian Tannezuft Shale Outline and Thermal Maturity

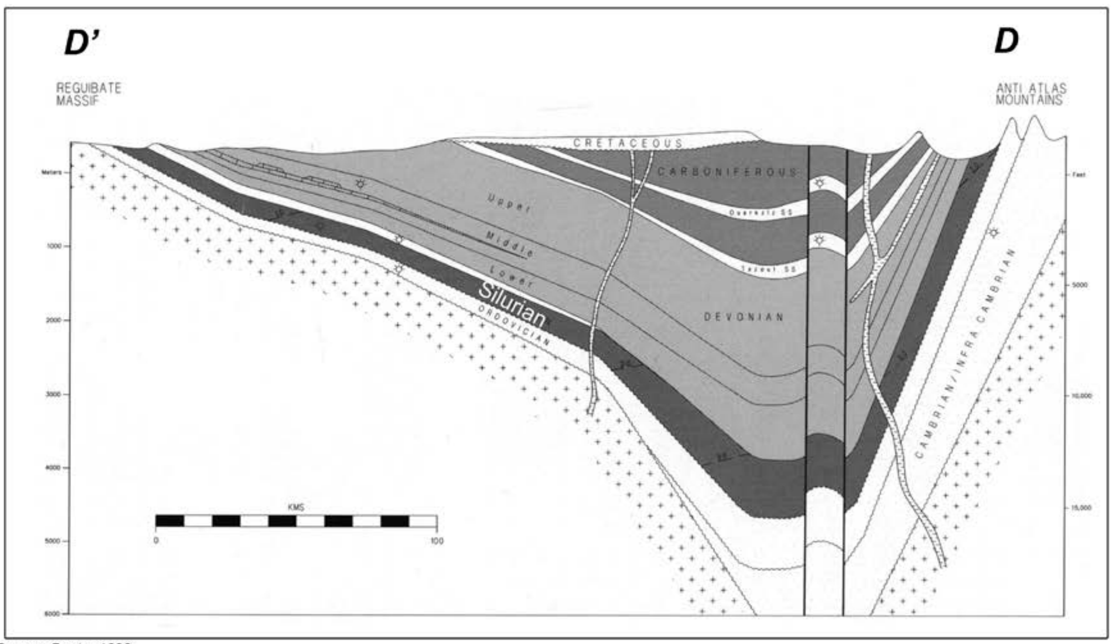


Source: ARI, 2013.

7.2 Reservoir Properties (Prospective Area).

The depth of the Silurian Tannezuft Shale in the prospective area ranges from 6,600 to 14,000 ft, averaging about 10,500 ft. While the total Upper Silurian section can be several thousand feet thick, the organic-rich portion of the Silurian Tannezuft Shale has a net thickness of only 54 ft where the TOC exceeds 2%. In the prospective area, the Tannezuft Shale is in both the wet gas/condensate and the dry gas windows (R_o > 1.0%) and has gas-prone Type III kerogen.[10,12] Figure XV-19 provides a cross-section for this frontier hydrocarbon basin.[13]

Figure XV-19. Tindouf Basin Cross Section



Source: Boote, 1998

Source: Boote, 1998.

7.3 Resource Assessment.

Within its 23,800-mi^2 dry gas prospective area, the Silurian Tannezuft Shale in the Tindouf Basin has a resource concentration of 24 Bcf/mi^2. Within its 5,340-mi^2 wet gas and condensate area, the shale has resource concentrations of 19 Bcf/mi^2 for wet gas and 1.7 million barrels/mi^2 for oil/condensate.

Within its overall 29,140-mi^2 prospective area, the risked resource in-place for the Tannezuft Shale in the Tindouf Basin is estimated at 135 Tcf of wet/dry shale gas and 2 billion barrels of shale oil/condensate. Of this, 26 Tcf of wet/dry shale gas and 0.1 billion barrels of shale oil/condensate are estimated as the risked, technically recoverable resource.

ACTIVITY

Algeria's natural gas and gas company, Sonatrach, has undertaken a comprehensive effort to define the size and quality of its shale gas (and oil) resources. To date, the company has established a data base of older cores, logs and other data and complemented this with information from new shale well logs in the main shale basins of Algeria. Next in the plan is to drill a series of pilot wells to test the productivity of the high priority basins, targeting shale formations with high TOC (>2%) and thick pay (>20m) at moderate depths (<3,000 m). The first pilot well within this comprehensive shale resource assessment program is scheduled for the Berkine (Ghadames) Basin, followed by test wells in the Illizi, Timimoun, Ahnet and Mouydir basins.[10] International energy companies, Statoil and Repsol, have also undertaken geological and reservoir characterization studies of Algeria's shales.[11]

Over the past year, Algeria has passed amendments to its federal legislation covering the hydrocarbon sector improving investment climate in anticipation of an expanded hydrocarbon licensing round due in 2013. However, the position of its stated-owned company Sonatrach is expected to remain dominant in this sector.

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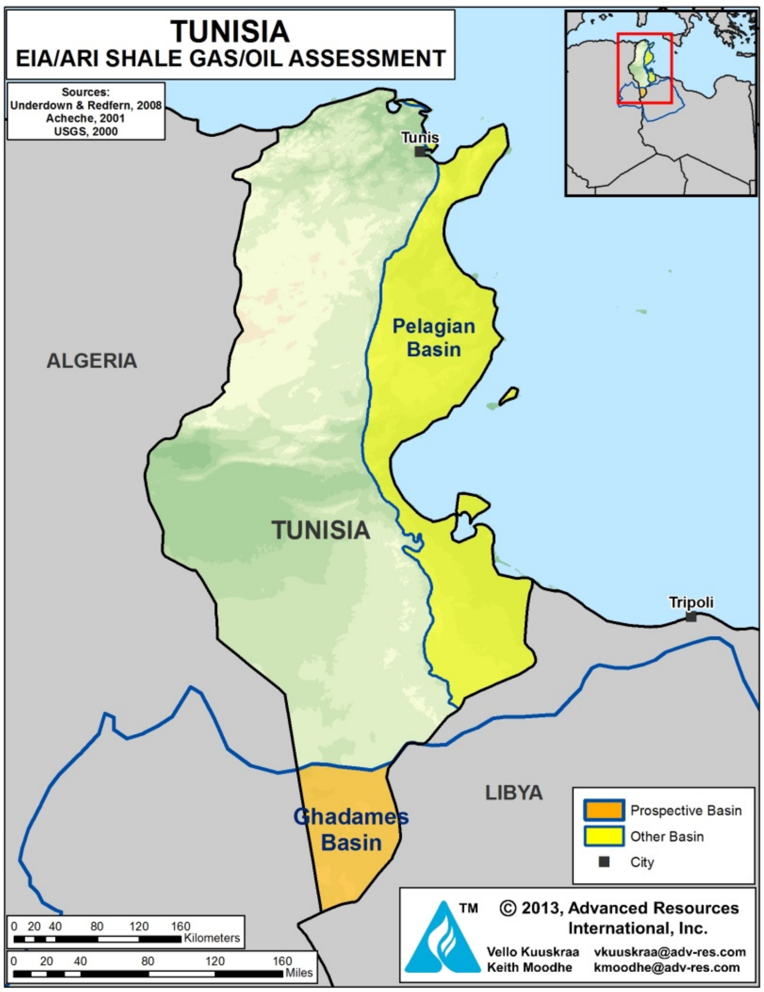
XVI. TUNISIA

SUMMARY

Tunisia has two significant formations with potential for shale gas and shale oil - - the Silurian Tannezuft "Hot Shale" and the Upper Devonian Frasnian Shale. These shale formations are in the Ghadames Basin, located in southern Tunisia. Additional shale gas and oil potential may exist in the Jurassic-Cretaceous and Tertiary petroleum systems in the Pelagian Basin of eastern Tunisia, as discussed further in this Chapter, Figure XVI-1.

Figure XVI-1. Tunisia's Shale Gas and Shale Oil Basins



Source: ARI, 2013.

Our assessment is that the Tannezuft and Frasnian shale formations in the Ghadames Basin contain 114 Tcf of risked shale gas in-place, with 23 Tcf as the risked, technically recoverable shale gas resource, Table XVI-1. In addition, these two shale formations contain 29 billion barrels of risked shale oil in-place, with 1.5 billion barrels as the risked, technically recoverable shale oil resource, Table XVI-2.

Table XVI-1. Shale Gas Reservoir Properties and Resources of Tunisia.

Basic Data	Basin/Gross Area		Ghadames ($117,000 mi^2$)				
	Shale Formation		Tannezuft		Frasnian		
	Geologic Age		Silurian		U. Devonian		
	Depositional Environment		Marine		Marine		
Physical Extent	Prospective Area (mi^2)		410	940	1,210	850	80
	Thickness (ft)	Organically Rich	115	115	197	197	197
		Net	104	104	177	177	177
	Depth (ft)	Interval	10,000 - 11,000	11,000 - 14,500	8,000 - 10,000	9,000 - 10,000	10,000 - 11,000
		Average	10,500	13,000	8,500	9,500	10,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.7%	5.7%	6.0%	6.0%	6.0%
	Thermal Maturity (% Ro)		1.15%	1.60%	0.85%	1.15%	1.35%
	Clay Content		Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		42.9	54.5	25.4	79.8	100.7
	Risked GIP (Tcf)		11.4	33.3	20.0	44.1	5.2
	Risked Recoverable (Tcf)		2.3	8.3	2.0	8.8	1.3

Table XVI-2. Shale Oil Reservoir Properties and Resources of Tunisia.

Basic Data	Basin/Gross Area		Ghadames ($117,000 mi^2$)		
	Shale Formation		Tannezuft	Frasnian	
	Geologic Age		Silurian	U. Devonian	
	Depositional Environment		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		410	1,210	850
	Thickness (ft)	Organically Rich	115	197	197
		Net	104	177	177
	Depth (ft)	Interval	10,000 - 11,000	8,000 - 10,000	9,000 - 10,000
		Average	10,500	8,500	9,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.7%	6.0%	6.0%
	Thermal Maturity (% Ro)		1.15%	0.85%	1.15%
	Clay Content		Medium	Medium	Medium
Resource	Oil Phase		Condensate	Oil	Condensate
	OIP Concentration ($MMbbl/mi^2$)		3.1	31.3	7.0
	Risked OIP (B bbl)		0.8	24.6	3.9
	Risked Recoverable (B bbl)		0.04	1.23	0.19

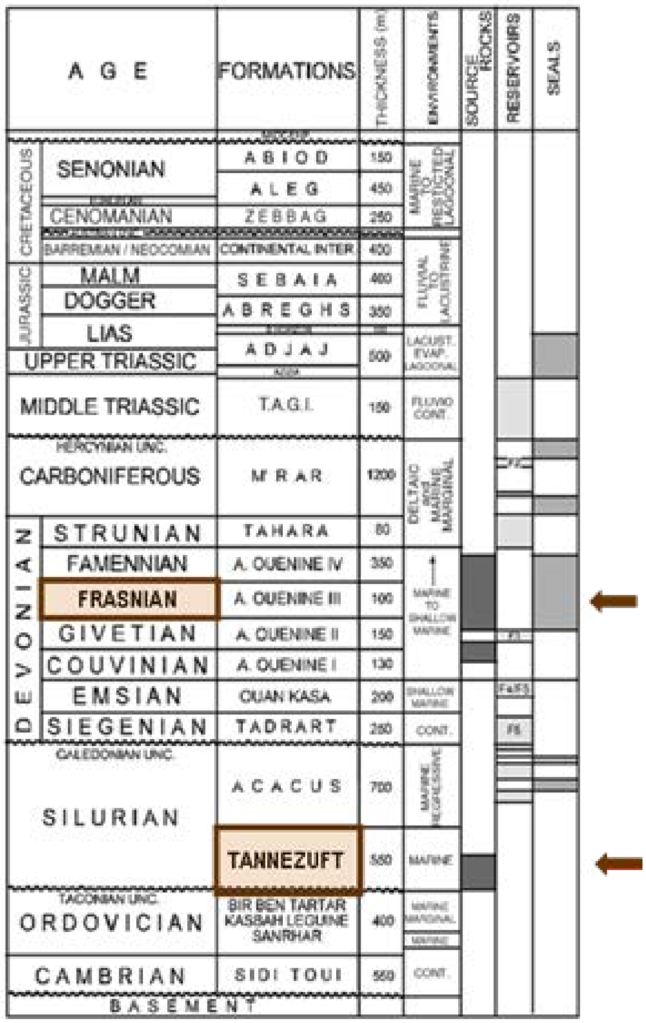
Advanced Resources International, Inc.

1. GHADAMES BASIN

1.1 Introduction and Geologic Setting

The Silurian-age Tannezuft "Hot Shale" (called "hot" because of its high uranium content; gamma-ray values >150 API units) is present in much of North Africa and the Middle East. This organic-rich shale has served as a major source rock for many of the conventional oil and gas fields in the region. The Upper Devonian-age Frasnian Shale is deposited above the deeper Tannezuft Shale. It has also served as an important source rock for the Devonian and Triassic conventional reservoirs in the region, Figure XVI-2.[1]

Figure XVI-2. Ghadames Basin Stratigraphic Column



Source: Acheche, M.H, 2001.

Prior geological and source rock studies by Acheche (2001),[1] Yahi (2001),[2] and Klett (2000),[3] as well as more recent information from oil and gas production companies operating in Tunisia[4,5,6,7] have provided valuable information on the geologic setting and reservoir properties of the shale formations of Tunisia.

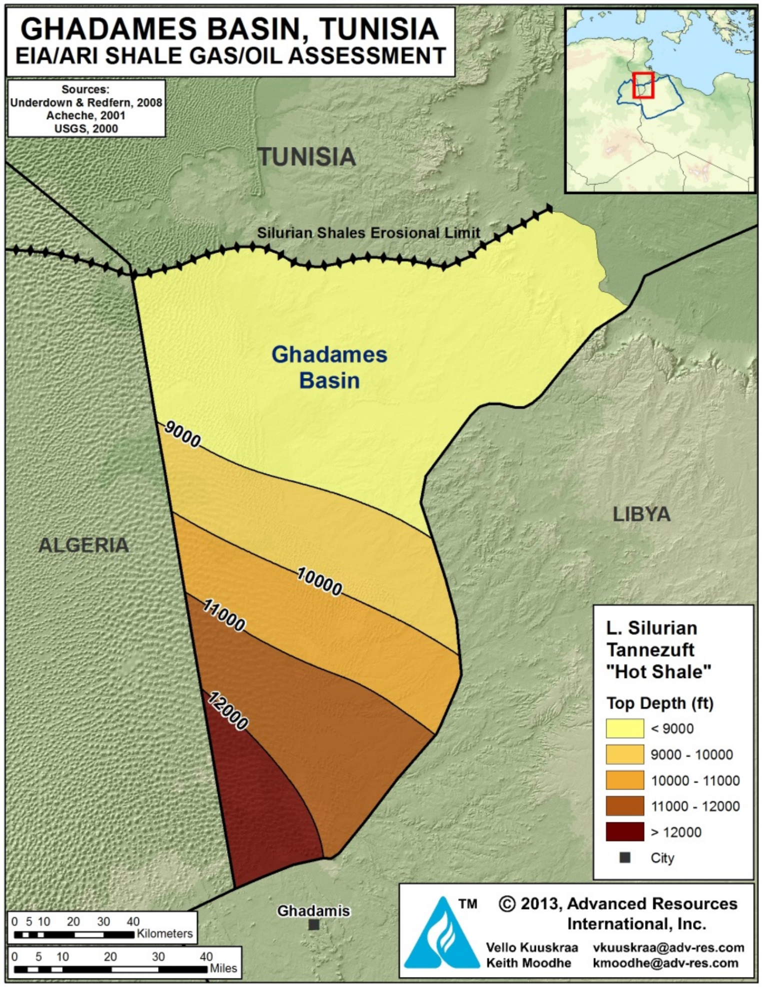
The Ghadames Basin and its two significant shale formations are located in the southern portion of Tunisia. Figures XVI-3 and XVI-4 provide the Ghadames Basin's shale outline and depth contours for the Silurian Tannezuft "Hot Shale"[1] and the Upper Devonian Frasnian Shale.

In Tunisia's portion of the Ghadames Basin, the Tannezuft Formation contains a organic-rich marine shale that grades from immature on the north to post-mature on the south. We have mapped a 1,350-mi^2 higher quality prospective area for the Tannezuft "Hot Shale" in the Ghadames Basin giving considerable emphasis to the recently assembled data on the mineralogy of the shale. The western and northern boundaries of the prospective area are defined by a change in shale deposition from higher quartz, lower clay to lower quartz, higher clay mineralogy. The eastern and southern borders of the prospective area are defined by the Tunisia and Libya border.

The northern portion of the Tannezuft "Hot Shale" prospective area covers 410 mi^2 and has thermal maturity of 1.0% to 1.3% R_o, placing this area in the wet gas and condensate window. The remaining prospective area of 940 mi^2 for the Tannezuft "Hot Shale", with R_o greater than 1.3%, is in the dry gas window, Figure XVI-5.

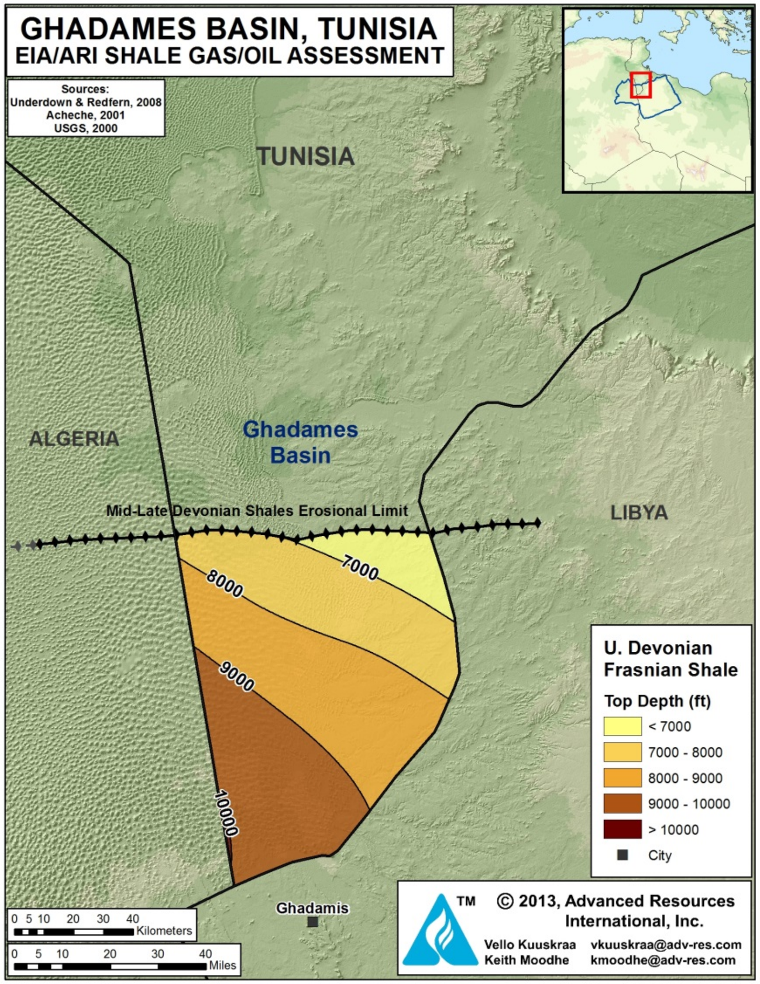
Deposited above the Tannezuft "Hot Shale" is the thermally less mature Frasnian Shale. We have mapped a 2,140-mi^2 prospective area for the Frasnian Shale in Tunisia's portion of the Ghadames Basin. The northern boundary of the Frasnian Shale prospective area is the minimum oil maturity criterion of 0.7% R_o. The western boundary of the prospective area is the Tunisia and Algeria border. The eastern and southern boundary of the Frasnian Shale prospective area is the Tunisia and Libya border.

Figure XVI-3. Ghadames Basin Silurian Tannezuft Shale Outline and Depth Contours



Source: ARI, 2013.

Figure XVI-4. Ghadames Basin Upper Devonian Frasnian Shale Outline and Depth Contours



Source: ARI, 2013.

The 1,210-mi^2 northern and eastern portion of the Frasnian Shale prospective area is in the oil window, with R_o between 0.7% and 1.0%. The 850-mi^2 central portion of the prospective area is in the wet gas and condensate window, with R_o between 1.0% and 1.3%. A relatively small 80-mi^2 area in the southwestern portion of the Frasnian Shale prospective area is in the dry gas window, with R_o above 1.3%, Figure XVI-6.

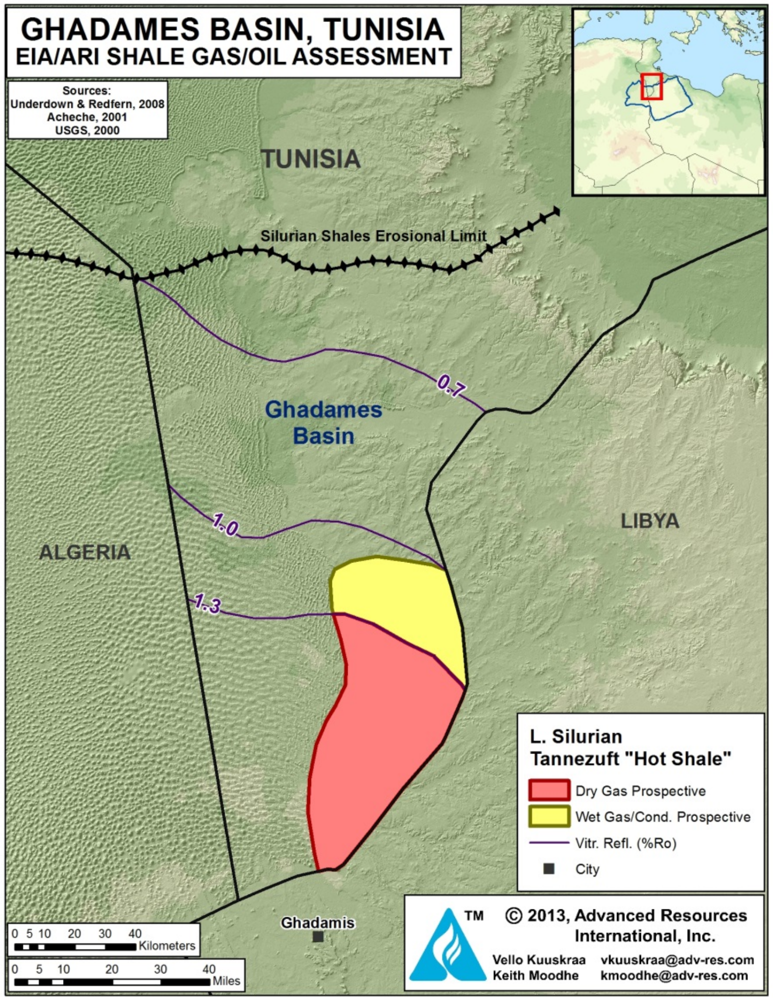
1.2 Reservoir Properties (Prospective Area)

Silurian Tannezuft Shale. The depth of the Silurian Tannezuft "Hot Shale" in the prospective area ranges from 10,000 ft along the northern and eastern basin edge to 14,500 ft in the basin center, averaging 10,500 ft in the wet gas area and 13,000 ft in the dry gas area, Figure XVI-3. The gross thickness of the Tannezuft "Hot Shale" is 115 ft, with an organic-rich average net thickness of 104 ft. (A thick package of Wenlockian silty sands overlies the Llandoverian "Hot Shales" within the Silurian Tannezuft Formation. These high porosity, potentially gas-charged silty sands are not included in our shale gas resource assessment.)

The TOC of the Tannezuft "Hot Shale" averages 5.7%. The lower portion of the formation is particularly organic-rich, with TOC values of up to 15%.[4] The thermal maturity of the Tannezuft "Hot Shale" ranges from wet gas (R_o of 1.0% to 1.3%) in the northern portion of the prospective area to dry gas (R_o >1.3%) in the southern portion of the prospective area in the Ghadames Basin, Figure XVI-5.

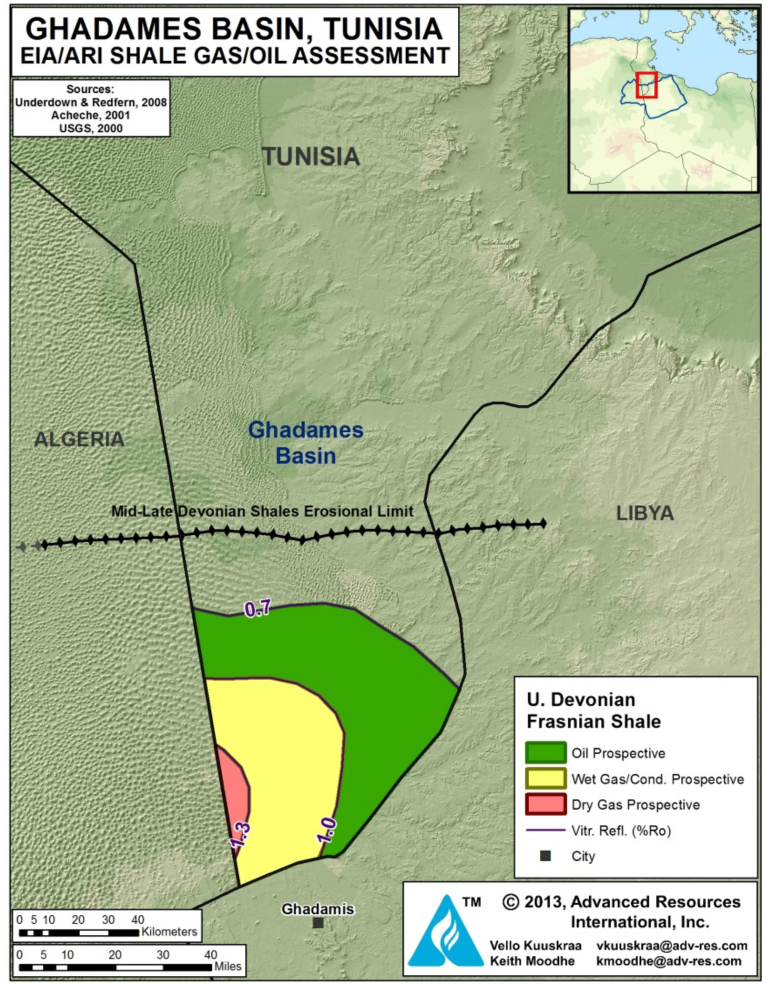
Upper Devonian Frasnian Shale. The depth of the overlying Upper Devonian Frasnian Shale in the prospective area ranges from 8,000 ft to 11,000 ft, averaging 8,500 ft in the oil-prone area, 9,500 ft in the wet gas/condensate area, and 10,500 ft in the dry gas area, Figure XVI-3. The Frasnian Shale has a gross thickness of 197 ft with an organic-rich net thickness of 177 ft. The Frasnian Shale has TOC values that range from 1% to 10% with an average of 6%.[3] The thermal maturity in the Frasnian Shale in the prospective area ranges from 0.7% in the north to over 1.3% R_o in the southwest, placing the shale in the oil, wet gas/condensate and dry gas windows, Figure XVI-5.

Figure XVI-5. Ghadames Basin Silurian Tannezuft "Hot Shale" Prospective Area



Source: ARI, 2013.

Figure XVI-6. Ghadames Basin Upper Devonian Frasnian Shale Prospective Area



Source: ARI, 2013.

1.3 Resource Assessment

Silurian Tannezuft Shale. The Tannezuft "Hot Shale", within its 410-mi^2 wet gas and condensate prospective area, has resource concentrations of 43 Bcf/mi^2 of wet gas and 3.1 million barrels/mi^2 of condensate. Within its 940-mi^2 dry gas prospective area, the Tannezuft "Hot Shale" has a resource concentration of 54 Bcf/mi^2.

The risked resource in-place for the overall 1,350-mi^2 wet gas/condensate and dry gas prospective area is 45 Tcf of shale gas and 0.8 billion barrels of shale oil. Based on moderate reservoir properties, particularly the medium level of clay content, we estimate risked, technically recoverable resources from the Tannezuft "Hot Shale" of 11 Tcf of shale gas and less than 0.1 billion barrels of shale oil, Tables XVI-1 and XVI-2.

Upper Devonian Frasnian Shale. The Frasnian Shale, within its overall 2,140-mi^2 prospective area has resource concentrations of 31 million barrels/mi^2 of oil (plus associated gas) in the 1,210-mi^2 oil window, 7 million barrels/mi^2 of condensate and 80 Bcf/mi^2 of wet gas in the 850-mi^2 wet gas/condensate window, and 101 Bcf/mi^2 of dry gas in the 80-mi^2 dry gas window.

The risked resource in-place within the overall 2,140-mi^2 prospective area is 69 Tcf of shale gas and 28.5 billion barrels of shale oil. Based on moderate reservoir properties, we estimate risked, technically recoverable resources from the Frasnian Shale of 12 Tcf of shale gas and 1.4 billion barrels of shale oil, Tables XVI-1 and XVI-2.

1.4 Recent Activity

Considerable exploration activity is underway in the Ghadames Basin, with much of the activity still devoted to conventional oil and gas resources. Cygam Energy has acquired four permits in the Ghadames Basin totaling 1.6 million net acres.[4] Cygam's exploration program involves 200 km of 3D seismic and two deep exploration wells. The company reportedly conducted a hydraulic stimulation in March 2010 on Well No. 1, completed in the Tannezuft Shale at a depth of 13,000 ft in their Sud Tozeur permit area. No information has been provided on test results. Cygam is seeking a JV partner to further develop its four Tunisia permit areas.

Chinook Energy Inc. has acquired a series of lease blocks in the Ghadames Basin, totaling 1.3 million net acres. The large Sud Remada block totals 1.2 million acres and targets the Tannezuft Shale as well as conventional formations.[5] The company plans to drill a deep exploration well in the Sud Remada lease block during 2013, targeting conventional Ordovician and Silurian resources. Previous drilling into the deeper, oil bearing "TT" Ordovician reservoir showed hydrocarbon potential in the Silurian Tannezuft Formation.

In early 2010, Perenco Tunisia reportedly drilled and hydraulically stimulated a deep Silurian well (Well #5) to test the shale gas potential in their El Franig Field. The company has not released data on the well's performance. In late 2012, Perenco reported that their gas production in Tunisia was all from conventional reservoirs and the company was not producing any shale gas. Winstar Resources, a small Canadian E&P company active in Tunisia, has sponsored an evaluation of the Silurian Tannezuft Shale in the Ghadames Basin of southern Tunisia. Winstar has acquired a series of concession areas in the basin and, with participation of ETAP (the state company), has committed to drilling a deep, test well (Sabria 12) in 2013.

2. OTHER BASINS

In addition to the shale gas and oil potential in the Ghadames Basin, Tunisia may also have shale resource potential in the less defined Pelagian Basin, located in the eastern portion of the country and extending into the offshore.

The Pelagian Basin contains two hydrocarbon systems with established shale source rocks. The first is the Jurassic-Cretaceous Petroleum System and its shale source rocks, particularly the Jurassic Nara Formation and the Early Cretaceous (Albian) Fahdene Formation contains Type II and III kerogen. The third potential shale source rock is the Late Cretaceous (Cenomanian to Turonian) Bahloul Formation containing Type II kerogen that underlies a limited portion of the basin. The thermal maturity of these source rocks ranges from early mature to late mature with TOCs that range from 0.5% to 14%, generally 1% to 3%. The oil generated from these Jurassic-Cretaceous source rocks is generally light, averaging 33^{o} API.

The second hydrocarbon system in the Pelagian Basin is the Tertiary Petroleum Systems and its Early Eocene Bou Dabbous Formation shale. The Bou Dabbous Shale contains Type I and II kerogen with TOC that ranges from 0.4% to 4%. The thermal maturities of the shale ranges from early mature to mature, providing a variety of oil gravities, ranging from 18^{o} to 53^{o} API.

A number of companies have begun exploration efforts in the Pelagian Basin, including a small Canadian-listed company, African Hydrocarbons and super-major Shell Oil. African Hydrocarbons has a minority interest in the 130,000-acre Bouhajla and Ktititir carbonate-chalk reservoir. While the company acknowledges that its lease acreage many also hold an unconventional shale play, it plans to target the "low hanging fruit" first.[8]

Shell Oil acquired a large lease position in the Pelagian Basin and has announced a $150 million exploration program to target conventional reservoirs as well as shale gas and shale oil potential on its lease acreage.

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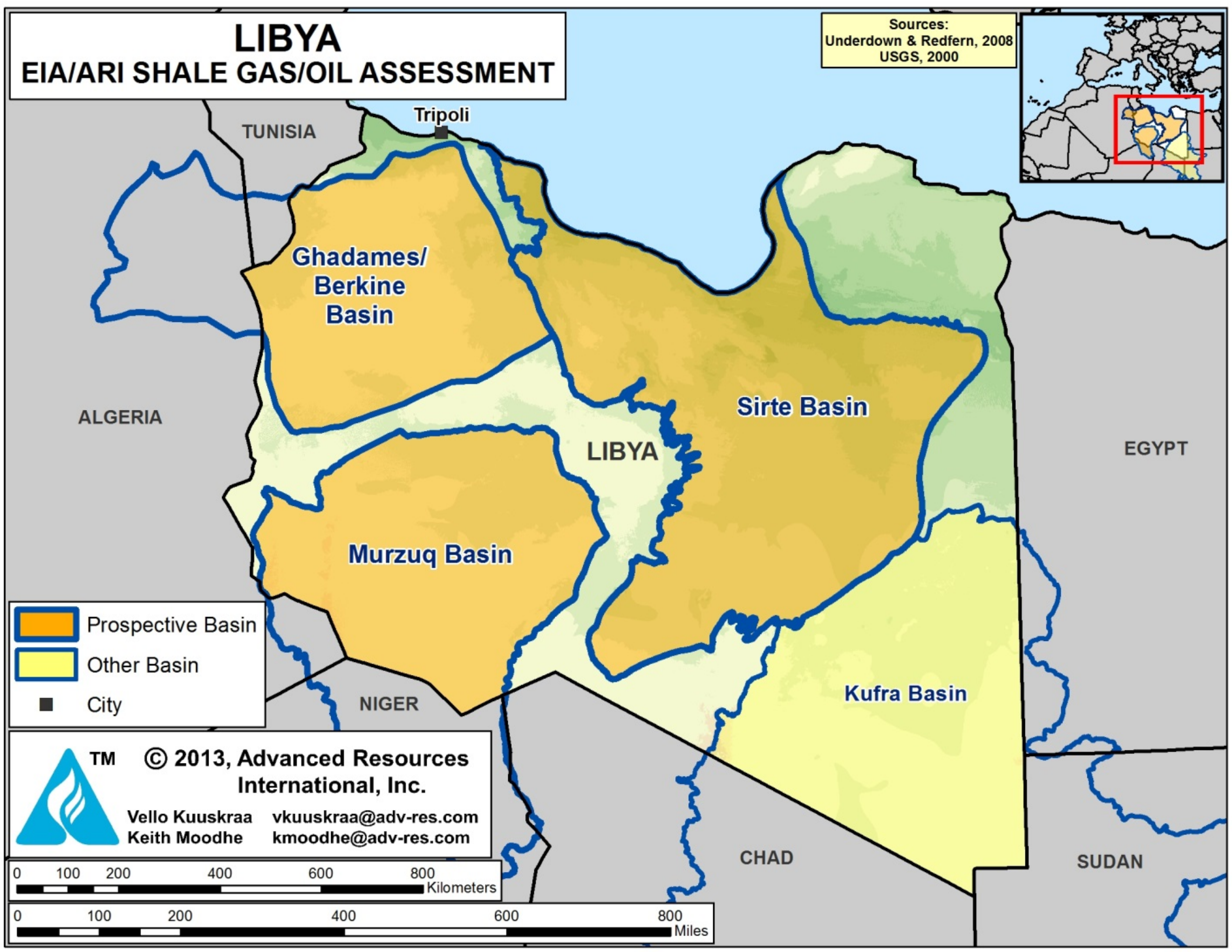
XVII. LIBYA

SUMMARY

This shale gas and shale oil resource assessment addresses three of Libya's major hydrocarbon basins: the Ghadames (Berkine) Basin in the west, the Sirte Basin in the center, and the Murzuq Basin in the southwest of the country, Figure XVII-1. One additional basin, the Kufra Basin in the southeast, is discussed but is not quantitatively assessed due to the speculative and limited nature of the available data.

Figure XVII-1. Shale Gas and Shale Oil Basins of Libya



Source: ARI, 2013.

We estimate that these three basins in Libya contain 942 Tcf of risked shale gas in-place, with 122 Tcf as the risked, technically recoverable shale gas resource, Tables XVII-1A and 1B. In addition, the shale formations in these three basins also contain 613 billion barrels of risked shale oil and condensate in-place, with 26.1 billion barrels as the risked, technically recoverable shale oil resource, Tables XVII-2A and 2B.

Table XVII-1A. Shale Gas Reservoir Properties and Resources of Libya.

Basic Data	Basin/Gross Area		Ghadames ($117,000\ mi^2$)					
	Shale Formation		Tannezuft			Frasnian		
	Geologic Age		L. Silurian			U. Devonian		
	Depositional Environment		Marine			Marine		
Physical Extent	Prospective Area (mi^2)		16,440	3,350	2,580	1,570	370	30
	Thickness (ft)	Organically Rich	115	115	115	197	197	197
		Net	104	104	104	177	177	177
	Depth (ft)	Interval	10,000 - 11,000	10,500 - 11,500	11,000 - 14,500	8,000 - 10,000	9,000 - 10,000	11,000 - 12,000
		Average	10,500	11,000	13,000	8,500	9,500	11,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.7%	5.7%	5.7%	6.0%	6.0%	6.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.60%	0.85%	1.15%	1.35%
	Clay Content		Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		11.8	43.4	54.5	25.4	79.8	93.1
	Risked GIP (Tcf)		96.9	72.7	70.3	19.9	14.8	1.4
	Risked Recoverable (Tcf)		9.7	14.5	17.6	2.0	3.0	0.3

Table XVII-1B. Shale Gas Reservoir Properties and Resources of Libya.

Basic Data	Basin/Gross Area		Sirte ($172,000\ mi^2$)		Murzuq ($97,000\ mi^2$)
	Shale Formation		Sirte/Rachmat	Etel Fm	Tannezuft
	Geologic Age		U. Cretaceous	U. Cretaceous	L. Silurian
	Depositional Environment		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		35,240	19,920	5,670
	Thickness (ft)	Organically Rich	2,000	600	67
		Net	200	120	60
	Depth (ft)	Interval	10,000 - 12,000	11,000 - 16,400	3,300 - 10,000
		Average	11,000	13,500	6,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Mod. Overpress.
	Average TOC (wt. %)		2.8%	3.6%	7.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.90%
	Clay Content		Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Assoc. Gas
	GIP Concentration (Bcf/mi^2)		24.8	37.4	6.5
	Risked GIP (Tcf)		349.8	297.9	18.6
	Risked Recoverable (Tcf)		28.0	44.7	1.9

Table XVII-2A. Shale Oil Reservoir Properties and Resources of Libya.

Basic Data	Basin/Gross Area		Ghadames (117,000 mi^2)			
	Shale Formation		Tannezuft		Frasnian	
	Geologic Age		L. Silurian		U. Devonian	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi^2)		16,440	3,350	1,570	370
	Thickness (ft)	Organically Rich	115	115	197	197
		Net	104	104	177	177
	Depth (ft)	Interval	10,000 - 11,000	10,500 - 11,500	8,000 - 10,000	9,000 - 10,000
		Average	10,500	11,000	8,500	9,500
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		5.7%	5.7%	6.0%	6.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		12.0	3.1	31.3	7.0
	Risked OIP (B bbl)		98.8	5.1	24.6	1.3
	Risked Recoverable (B bbl)		4.94	0.26	1.23	0.06

Table XVII-2B. Shale Oil Reservoir Properties and Resources of Libya.

Basic Data	Basin/Gross Area		Sirte (172,000 mi^2)		Murzuq (97,000 mi^2)
	Shale Formation		Sirte/Rachmat	Etel Fm	Tannezuft
	Geologic Age		U. Cretaceous	U. Cretaceous	L. Silurian
	Depositional Environment		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		35,240	19,920	5,670
	Thickness (ft)	Organically Rich	2,000	600	67
		Net	200	120	60
	Depth (ft)	Interval	10,000 - 12,000	11,000 - 16,400	3,300 - 10,000
		Average	11,000	13,500	6,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Mod. Overpress.
	Average TOC (wt. %)		2.8%	3.6%	7.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.90%
	Clay Content		Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Oil
	OIP Concentration (MMbbl/mi^2)		28.8	6.3	9.5
	Risked OIP (B bbl)		405.9	50.5	26.9
	Risked Recoverable (B bbl)		16.24	2.02	1.34

INTRODUCTION

Libya is one of the important hydrocarbon producing countries of North Africa, with a successful history of oil and gas exploration, particularly in the Sirte Basin. The geologic setting of Libya's sedimentary basins is complex, having been formed by a series of tectonic events, the Hercynian that separated the area into a series of horsts and grabens (uplifts and troughs) filled with Cambrian though Oligocene sediments. This tectonic overprint is a key factor in defining and limiting the shale gas and oil prospective areas, as discussed for each of these assessed basins of Libya.

The regionally dominant Lower Silurian Tannezuft basal or "hot shale" and the Upper Devonian Frasnian Shale are assessed in the Ghadames (Berkine) Basin. Two distinct Late Cretaceous shales -- Sirte/Rachmat and Etel -- are the subject of our shale resource assessment in the Sirte Basin. The basal "hot shale" within the Silurian Tannezuft Formation is the main shale formation assessed in the Murzuq Basin.

While our shale resource assessment has targeted three of Libya's most prospective basins and their shale source rocks, it is likely that future exploration will identify additional shale resources in other basins and formations.

1. GHADAMES (BERKINE) BASIN

1.1 Introduction and Geologic Setting

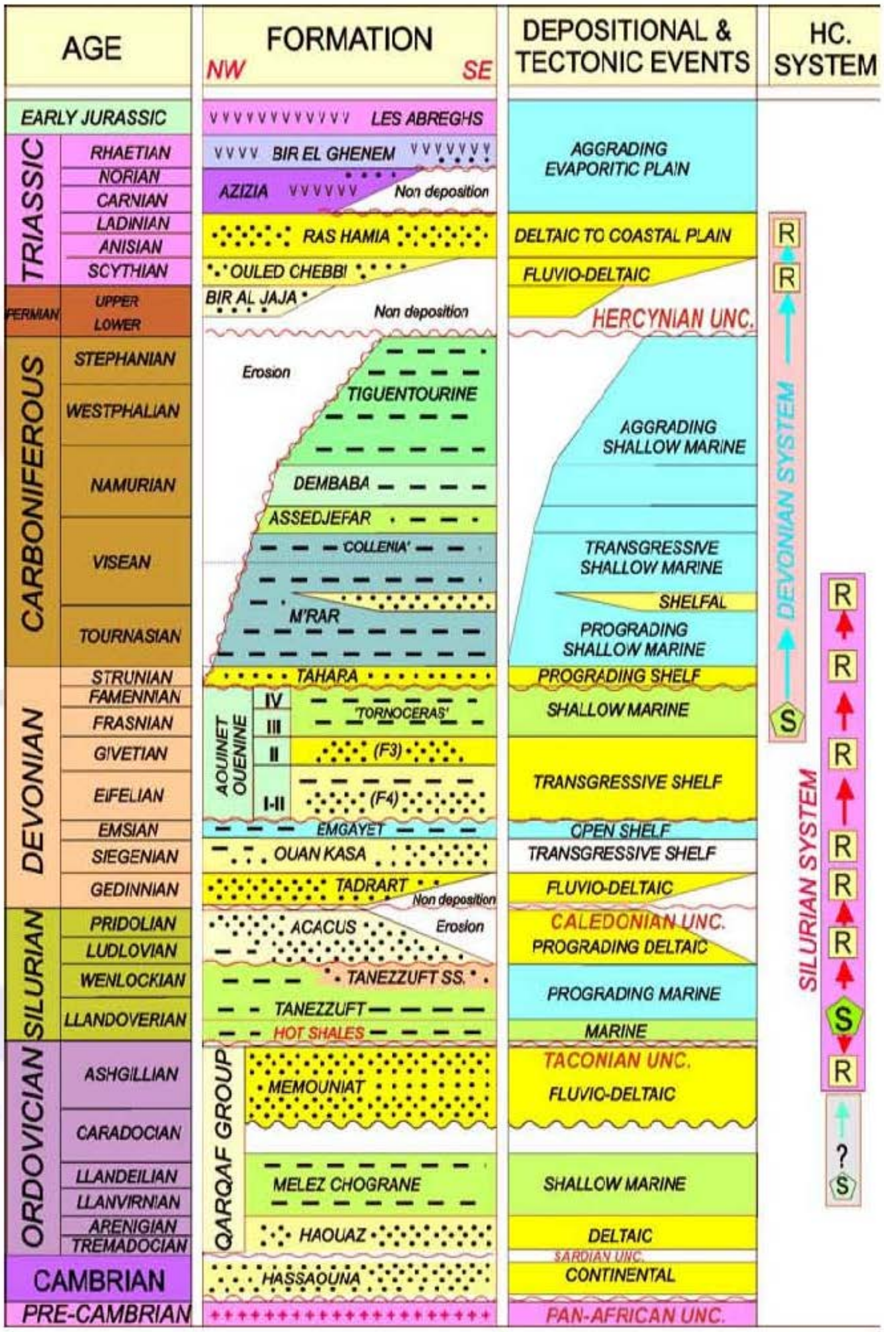
The Ghadames (Berkine) Basin is a large intra-cratonic basin underlying eastern Algeria and southern Tunisia. It encompasses an 84,000-mi^2 area in northwestern Libya and hosts two significant shale formations, the Lower Silurian Tannezuft and the Upper Devonian Frasnian, Figure XVII-2.[1]

In Libya's portion of the Ghadames Basin, the Silurian Tannezuft Formation contains a basal organic-rich marine shale ("hot shale") that increases in maturity toward the basin center. We have mapped a 22,370-mi^2 higher quality area for the Tannezuft "hot shale" in this basin, comprising separate dry gas, wet gas/condensate, and oil-prone windows. The southern, northern and eastern boundaries of the Tannezuft Shale prospective area are defined by uplifts, the erosional limits of the Silurian, and by thermal maturity. (Due to limited thermal maturity data for the eastern portion of the prospective area, we relied on the ring of discovered oil fields as the eastern boundary.) The western boundaries of the prospective area is defined by the Libya, Tunisia and Algerian border.

The central, dry-gas portion of the 2,580-mi^2 Tannezuft Shale prospective area in the Ghadames Basin has a thermal maturity (R_o) ranging from 1.3% to over 2%. The wet gas/condensate prospective area covers 3,350 mi^2 and has a R_o between 1.0% and 1.3%. The remainder of the prospective area of 16,440 mi^2 is in the oil window, with a R_o of 0.7% to 1.3%, Figure XVII-3.

The Upper Devonian Frasnian Shale is deposited above the Tannezuft Formation. The Frasnian Shale is more limited in area and is thermally less mature. We have mapped a 1,970-mi^2 higher quality prospective area for the Frasnian Shale in the Ghadames Basin of Libya. The eastern, northern and southern boundaries of the Frasnian Shale prospective area in this basin are set by the minimum thermal maturity criterion of 0.7% R_o. The western boundary of the prospective area is the Tunisia, Algeria, and Libyan border.

Figure XVII-2. Ghadames Basin Stratigraphic Column



Source: Seddiq Hussein, 2004.

The northern, eastern and southern outer ring of the Frasnian Shale prospective area in the Ghadames Basin, encompassing an area of 1,570 mi^2, is in the oil window with R_o between 0.7% and 1.0%. The central, quite small 30-mi^2 portion of the Frasnian Shale prospective area is in the dry gas window, with R_o of 1.3% to over 2%. In between is the 370-mi^2 wet gas and condensate area for the Frasnian Shale, with R_o between 1.0% and 1.3%, Figure XVII-4.

1.2 Reservoir Properties (Prospective Area)

Silurian Tannezuft Formation. The depth of the gas prospective area of the Silurian Tannezuft Shale in the Ghadames (Berkine) Basin of Libya ranges from 10,000 ft along the northern and eastern edge of the basin to 14,500 ft toward the basin center, averaging about 13,000 ft in the dry gas area, 11,000 ft in the wet gas area, and 10,500 ft in the oil area. The lower organic-rich basal shale unit has a net thickness of 104 ft. The TOC of the basal Tannezuft Shale averages 5.7%.[2]

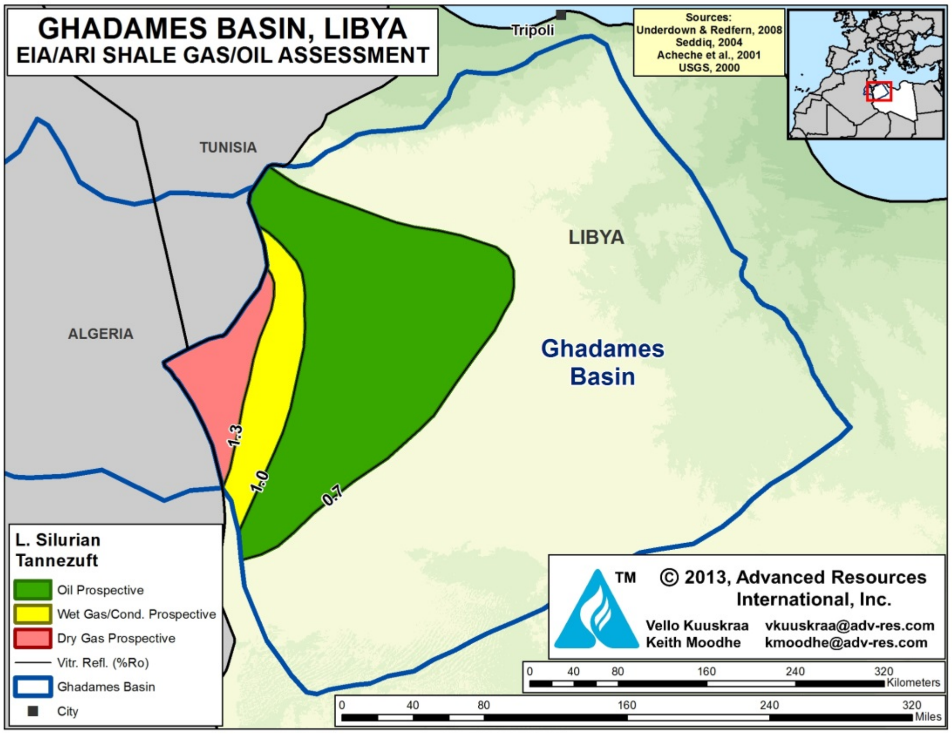
Upper Devonian Frasnian Formation. The depth of the prospective area of the overlying Upper Devonian Frasnian Shale in the Ghadames (Berkine) Basin of Libya ranges from 8,000 to 12,000 ft, averaging 8,500 ft in the oil-prone area; 9,500 ft in the wet gas/condensate area; and 11,500 ft in the dry gas area. The organic-rich portion of the Frasnian Shale has an average net thickness of 177 ft. The Frasnian Shale has TOC values ranging from 3% to 10%, with an average of 6%.[3]

1.3 Resource Assessments

Silurian Tannezuft Shale. The Tannezuft Shale, within its 2,580-mi^2 dry gas prospective area, has a resource concentration of 54 Bcf/mi^2. Within its larger 3,350-mi^2 wet gas and condensate prospective area, the Tannezuft Shale of the Ghadames (Berkine) Basin has resource concentrations of 43 Bcf/mi^2 of wet gas and 3 million barrels/mi^2 of condensate. The resource concentration in the 16,440 mi^2 oil prospective area is 12 million barrels/mi^2.

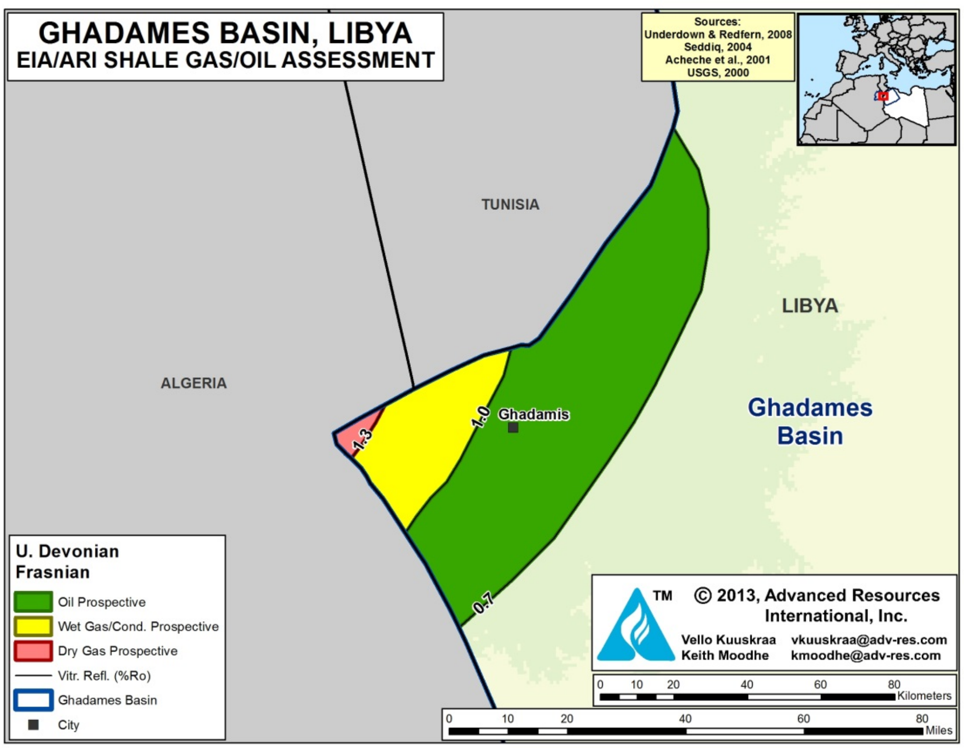
The risked resource in-place for the prospective areas of the Tannezuft Shale is 104 billion barrels of shale oil/condensate and 240 Tcf of wet and dry shale gas. Given concerns with presence of clays but otherwise favorable reservoir properties, we estimate a risked, technically recoverable shale oil/condensate resource of 5.2 billion barrels and 42 Tcf of wet and dry shale gas.

Figure XVII-3. Ghadames Basin Silurian Tannezuft Shale Outline and Thermal Maturity



Source: ARI, 2013

Figure XVII-4. Ghadames Basin Upper Devonian Frasnian Shale Outline and Thermal Maturity



Source: ARI, 2013

Upper Devonian Frasnian Shale. The Frasnian Shale has resource concentrations of 31 million barrels/mi^2 for oil (plus associated gas) in the 1,570-mi^2 oil window, 7 million barrels/mi^2 of condensate and 8 Bcf/mi^2 of wet gas in the 370-mi^2 wet gas/condensate window, and 93 Bcf/mi^2 of dry gas in the 30-mi^2 dry gas window.

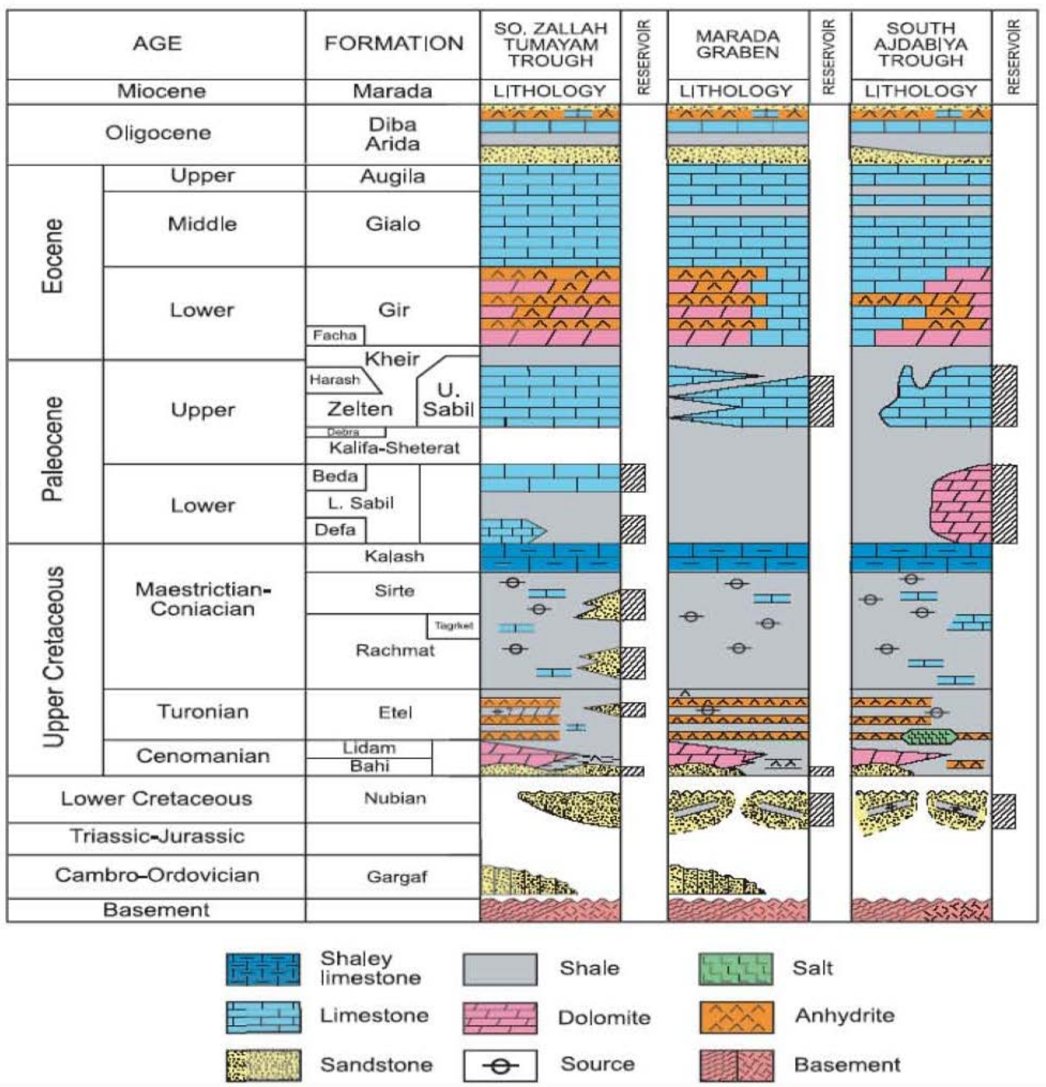
The risked resource in-place for the prospective areas is 23 billion barrels of oil/condensate and 33 Tcf of wet/dry shale gas, with risked, recoverable shale oil of 1.2 billion barrels and 4 Tcf of wet/dry shale gas.

2. SIRTE BASIN

Introduction and Geologic Setting

The Sirte Basin, covering an area of 172,000 mi^2 in central Libya, is the most prolific hydrocarbon basin in North Africa. The Sirte Basin contains sixteen giant oil and gas fields (defined as fields containing more than 500 million barrels of oil equivalent. To date, the Sirte Basin has yielded 45 billion barrels of oil and 33 Tcf of natural gas discoveries (SEPM Strata, 2013). The Upper Cretaceous Sirte/Rachmat and Etel shales are the principal source rocks for these hydrocarbon discoveries and are the two organic-rich shale formations addressed by this resource study, Figure XVII-5.[1]

Figure XVII-5. Sirte Basin Stratigraphic Column



Source: Seddiq Hussein, 2004

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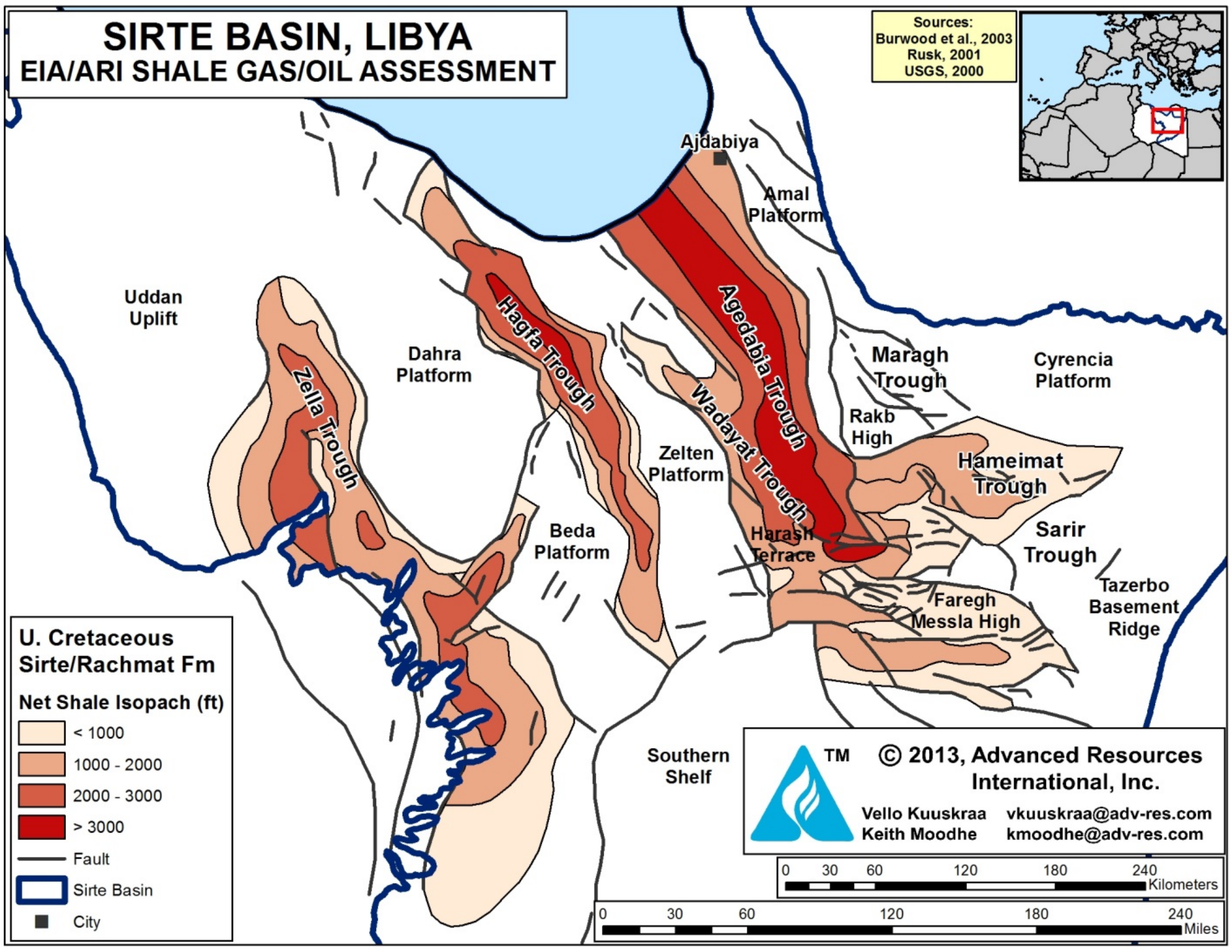
2.1 Geologic Setting

The Sirte Basin consists of a series of horst and graben structures trending northwest to southeast including the Hameimat, Agedabia, Wadayat, Hagfa and Zella, as shown in Figure XVII-6. These troughs contain the two main shale formations evaluated by this study - - the Upper Cretaceous Sirte/Rachmat Shale and the underlying Upper Cretaceous Etel Shale. We have mapped an oil-prospective area totaling 35,240 mi^2 for the Sirte/Rachmat Shale in these five troughs, similarly, we have mapped a 19,920-mi^2 wet gas/condensate area for the areally more limited Etel Shale in these five troughs.

Figure XVII-6. Sirte Basin Net Shale Isopach for the Sirte/Rachmat Shale

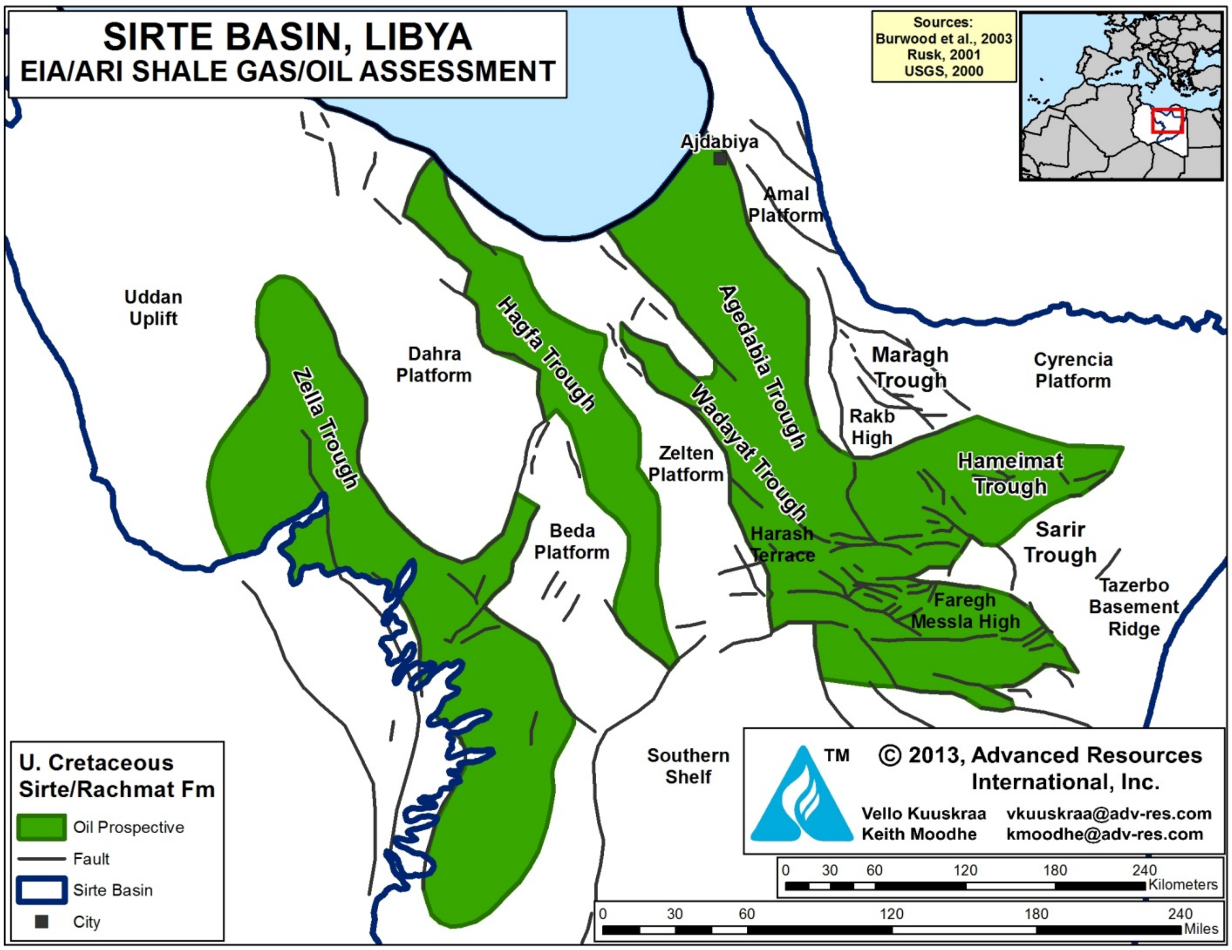


Source: ARI, 2013

2.2 Reservoir Properties (Prospective Area)

Sirte/Rachmat Shale. Within the oil-prospective area of the Sirte Basin, the Sirte/Rachmat Shale is present in a series of troughs at depths of 10,000 to 12,000 ft, averaging 11,000 ft, Figure VXII-7. The total Sirte/Rachmat Formation has a gross thickness of 2,000 ft with a net organic-rich shale section of 200 ft. The TOC of the organic–rich shale interval averages 2.8% and the shale is in the oil window (R_o of 0.7% to 1.0%).

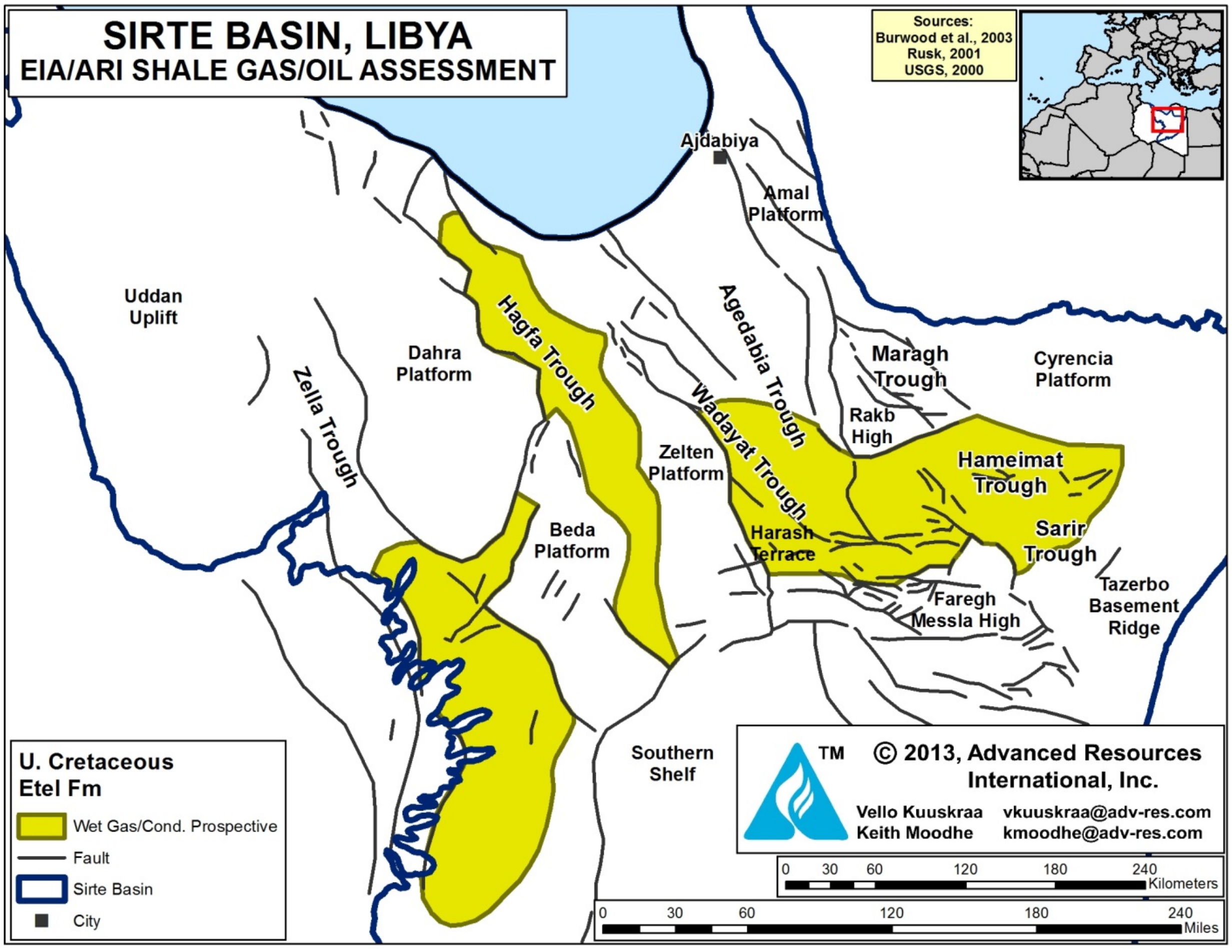
Figure XVII-7. Sirte Basin, Sirte/Rachmat Shale Prospective Area



Source: ARI, 2013

Etel Shale. The Etel Shale's 19,920-mi^2 prospective area underlies the Sirte/Rachmat Shale at depths of 11,000 to 16,400 ft, averaging 13,500 ft, Figure XVIII-8. The Etel Formation is about 600 ft thick, of which 120 net ft is organic-rich shale. The TOC of the organic-rich shale is high at 3.6%. The thermal maturity (R_o) of 1.0% to 1.3% places the Etel Shale in the wet gas/condensate window.

Figure XVII-8. Sirte Basin, Etel Shale Prospective Area



Source: ARI, 2013

2.3 Resource Assessment

Sirte/Rachmat Shale. The Upper Cretaceous Sirte/Rachmat Shale, within its 35,240-mi^2 prospective area for oil, has an oil concentration of 29 million barrels/mi^2, plus associated gas. The risked shale oil in-place is estimated at 406 billion barrels, with 16.2 billion barrels as risked, technically recoverable. In addition, we estimate a risked associated shale gas in-place of 350 Tcf, with 28 Tcf as the risked, technically recoverable shale gas resource.

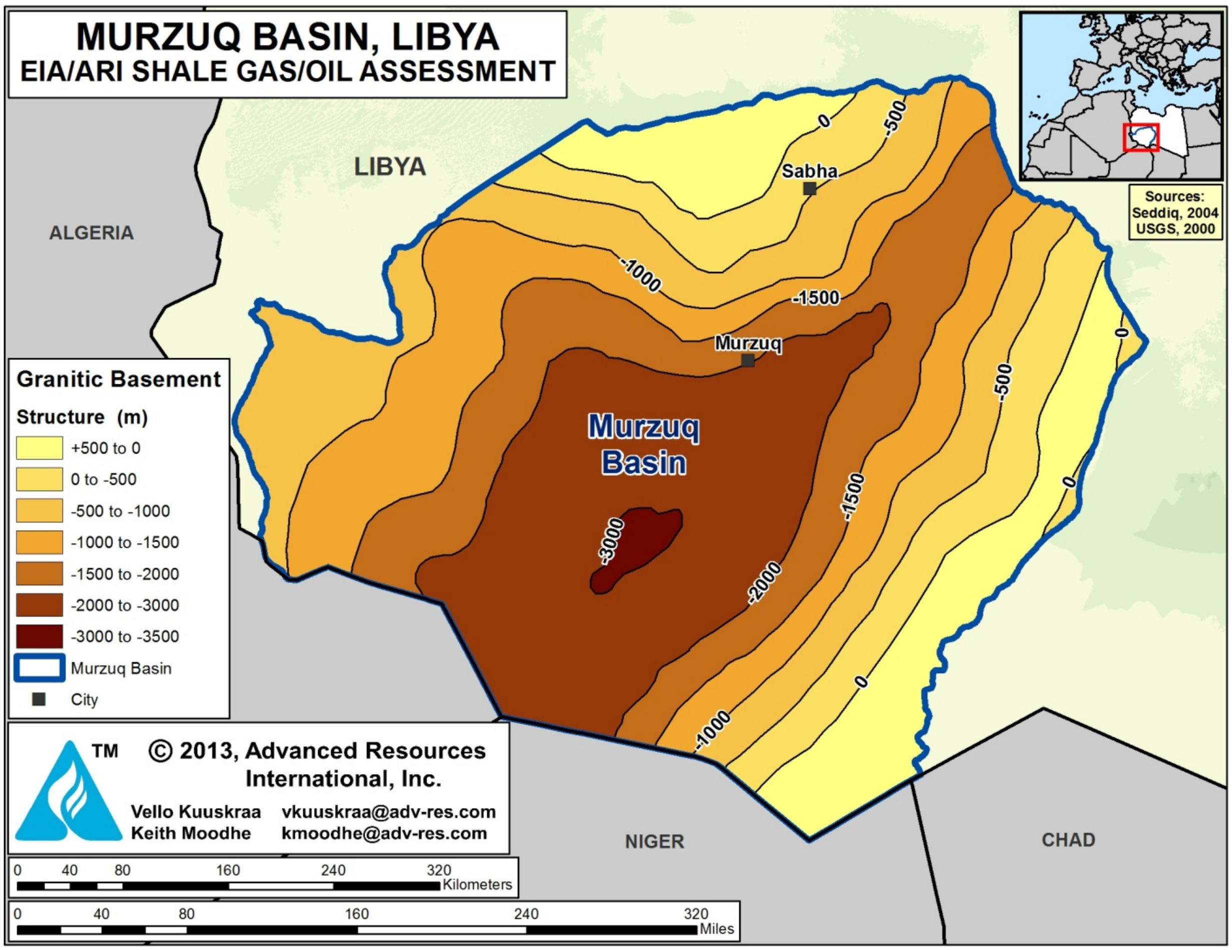
Etel Shale. The Upper Cretaceous Etel Shale has a prospective area of 19,920 mi^2 for wet gas and condensate. The Etel Shale has resource concentrations of 6 million barrels of oil and 37 Bcf of wet gas per square mile. With risked resources in-place of 51 billion barrels of oil/condensate and 298 Tcf of wet gas, the risked, technically recoverable shale oil and gas resources are estimated at 2.0 billion barrels of shale oil/condensate and 45 Tcf of shale gas.

3. MURZUQ BASIN

Introduction

The Murzuq Basin extends over a large 97,000-mi^2 area in the southwestern portion of Libya (extending southward into the Republic of Chad), Figure XVII-9. With its remote location, the Murzuq Basin remained undiscovered and unproven for hydrocarbons until the 1980s. Since then, four large discoveries, including the giant Elephant field plus numerous smaller fields, account for 5.4 billion barrels of discovered oil in-place, with 1.75 billion barrels estimated as recoverable.

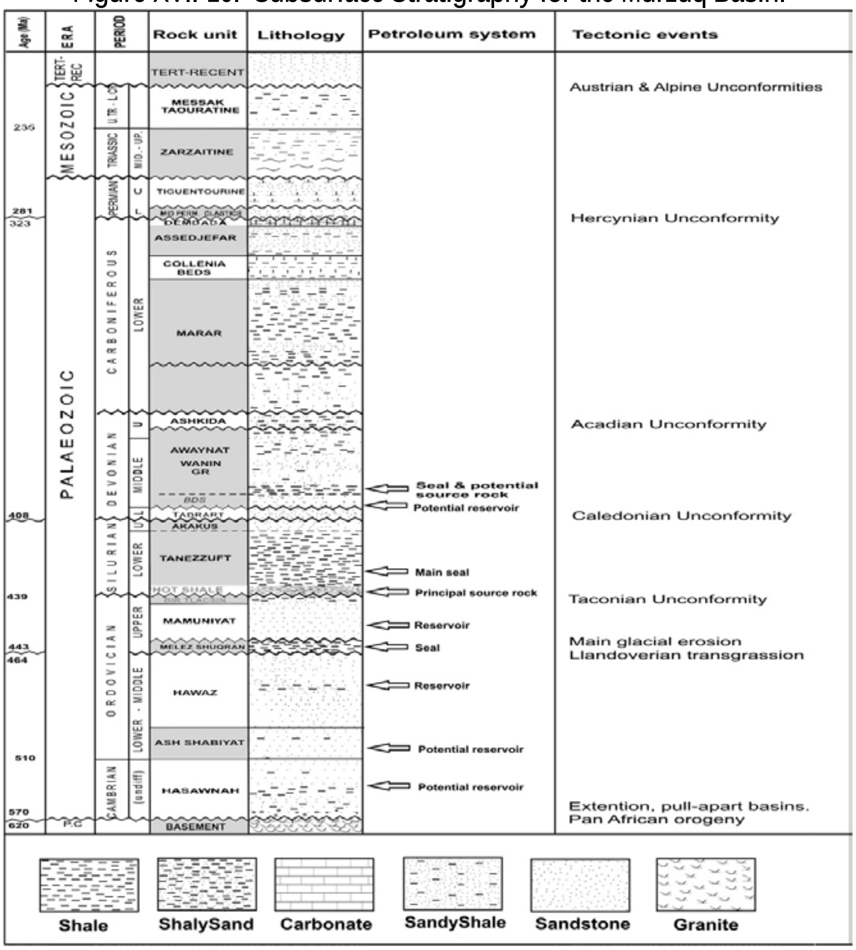
Figure XVII-9. Basin Outline and Structural Contour Map (Granitic Basement) for the Murzuq Basin



Source: ARI, 2013

The primary shale source rock addressed in the Murzuq Basin resource study is the Lower Silurian Tannezuft Formation, notably the “hot shale” interval at the base of the formation, Figure XVII-10.[4] Another potential source rock in this basin, not further assessed due to lack of data and concern with respect to thermal maturity, is the Middle Devonian Awaynat Formation in the deep center of the basin.

Figure XVII-10. Subsurface Stratigraphy for the Murzuq Basin.

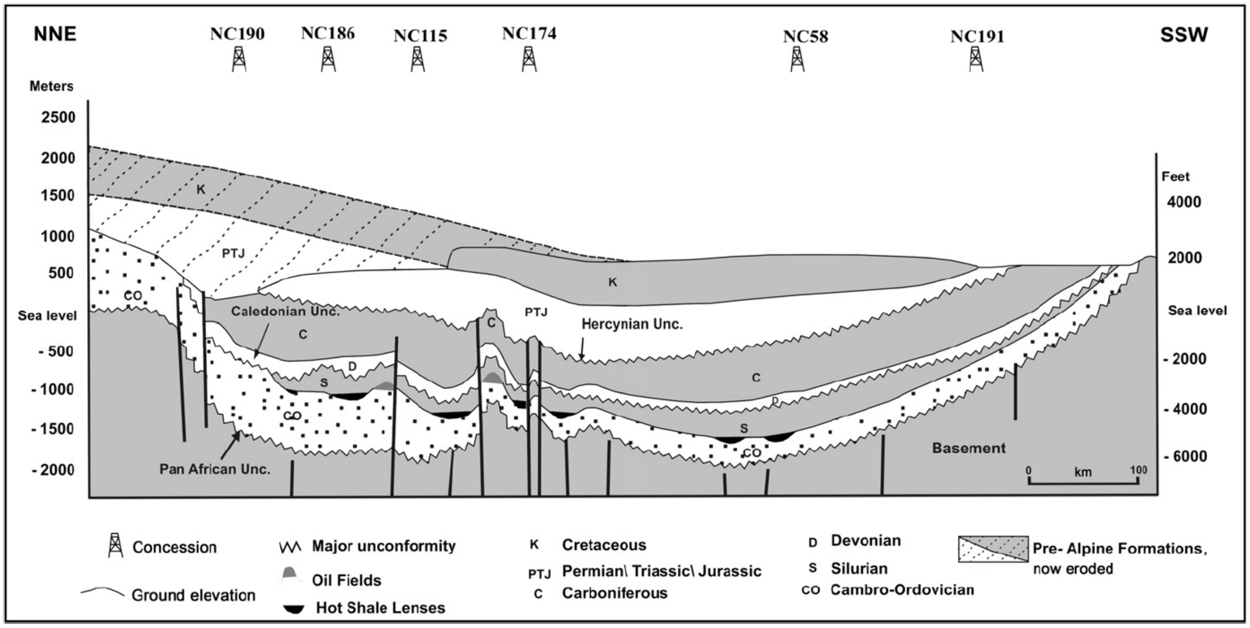


Source: Belaid at al., 2010

3.1 Geologic Setting

The Murzuq Basin is bounded on the east by the Tibisti Arch, on the west by the Tihembada Arch (which separates it from the Illizi Basin in Algeria), on the north by the Qurcal Arch (which separates it from the Ghadames Basin), and on the south by the Libya and Chad borders. Figure XVII-11[4] provides a generalized cross-section across the northern portion of the Murzuq Basin.

Figure XVII-11. Cross-Section for Murzuq Basin



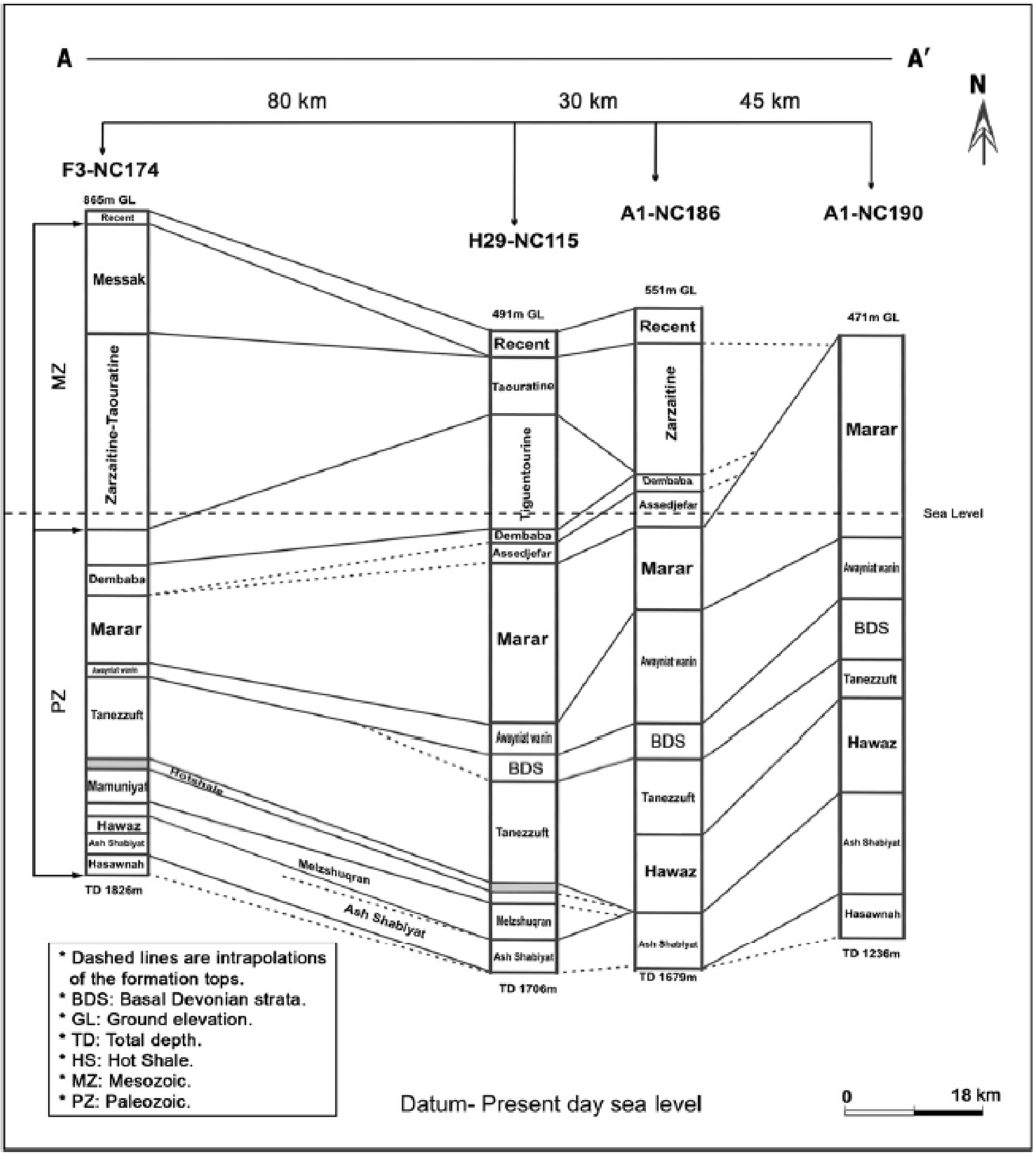
Source: Belaid at al., 2010

The intra-cratonic Murzuq Basin contains a series of troughs and uplifts that dominate the basin's deposition and hydrocarbon potential. Of particular significance is the Awabari Trough in the center of the basin where a series of cored wells (F3-NC174 and H29-NC115) have been drilled that provide a most valuable data set for this resource assessment. Within this trough, the Silurian Tannezuft Formation, particularly its lower "hot shale" interval, is the primary hydrocarbon source rock for the oil discoveries in the Murzuq Basin. The presence of this shale interval is illustrated by the cross-section on Figure XVII-12,[4] with the cross-section location provided on Figure XVII-13.[4]

3.2 Reservoir Properties (Prospective Area).

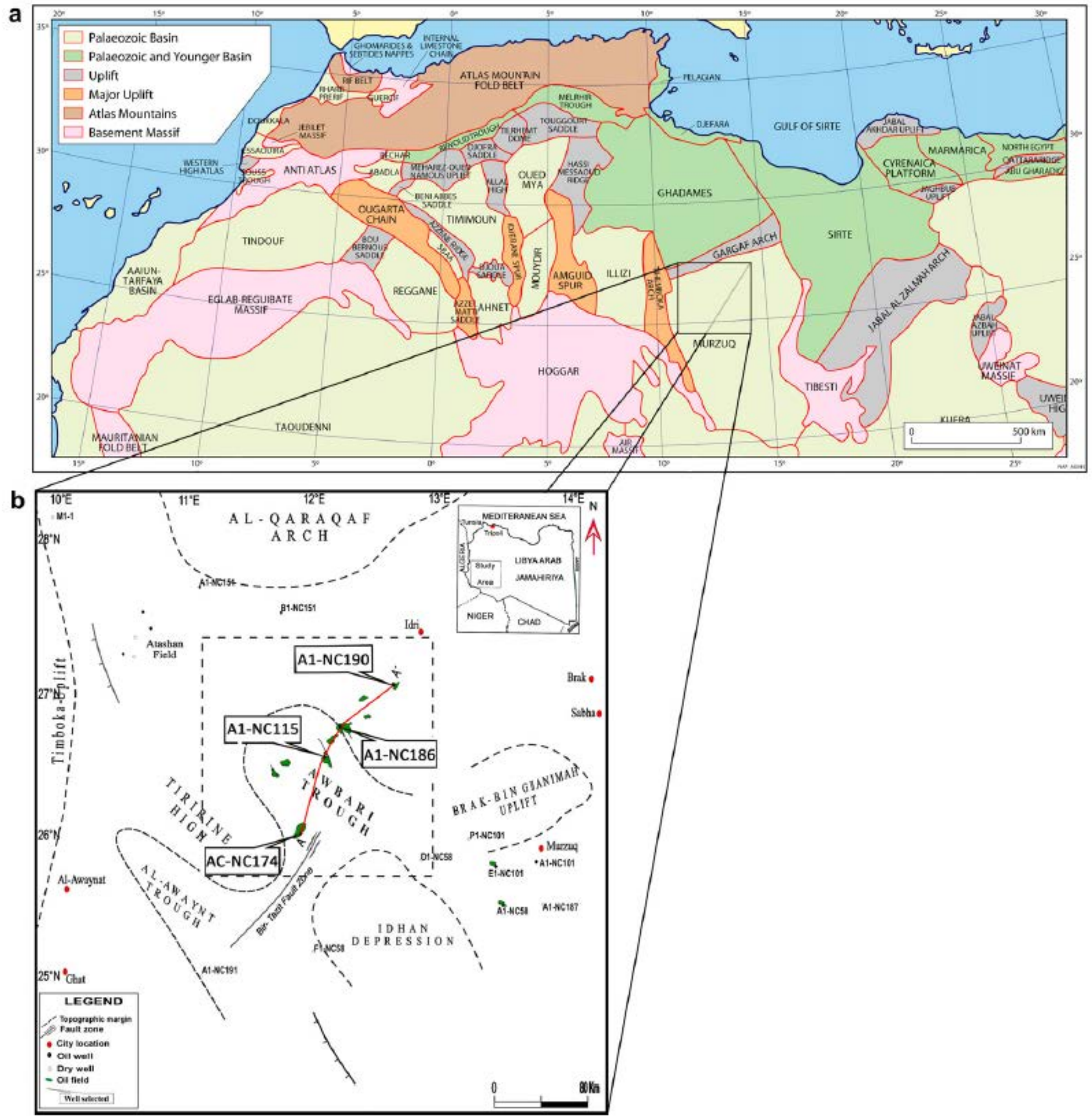
Lower Silurian Tannezuft Shale. The Silurian Tannezuft Formation (early Llandoverian) consists of dark gray to black graptolitic shales with intervals of siltstone and fine-grained sandstone deposited in a marine environment.[5]

Figure XVII-12. General Stratigraphy and Cross Section (A-A') for Four Murzuq Basin Study Wells
(See Figure XVIII-13 for Cross-Section Locations)



Source: Belaid et al., 2010

Figure XVII-13. Awabari Trough of the Murzuq Basin



Source: Belaid at al., 2010

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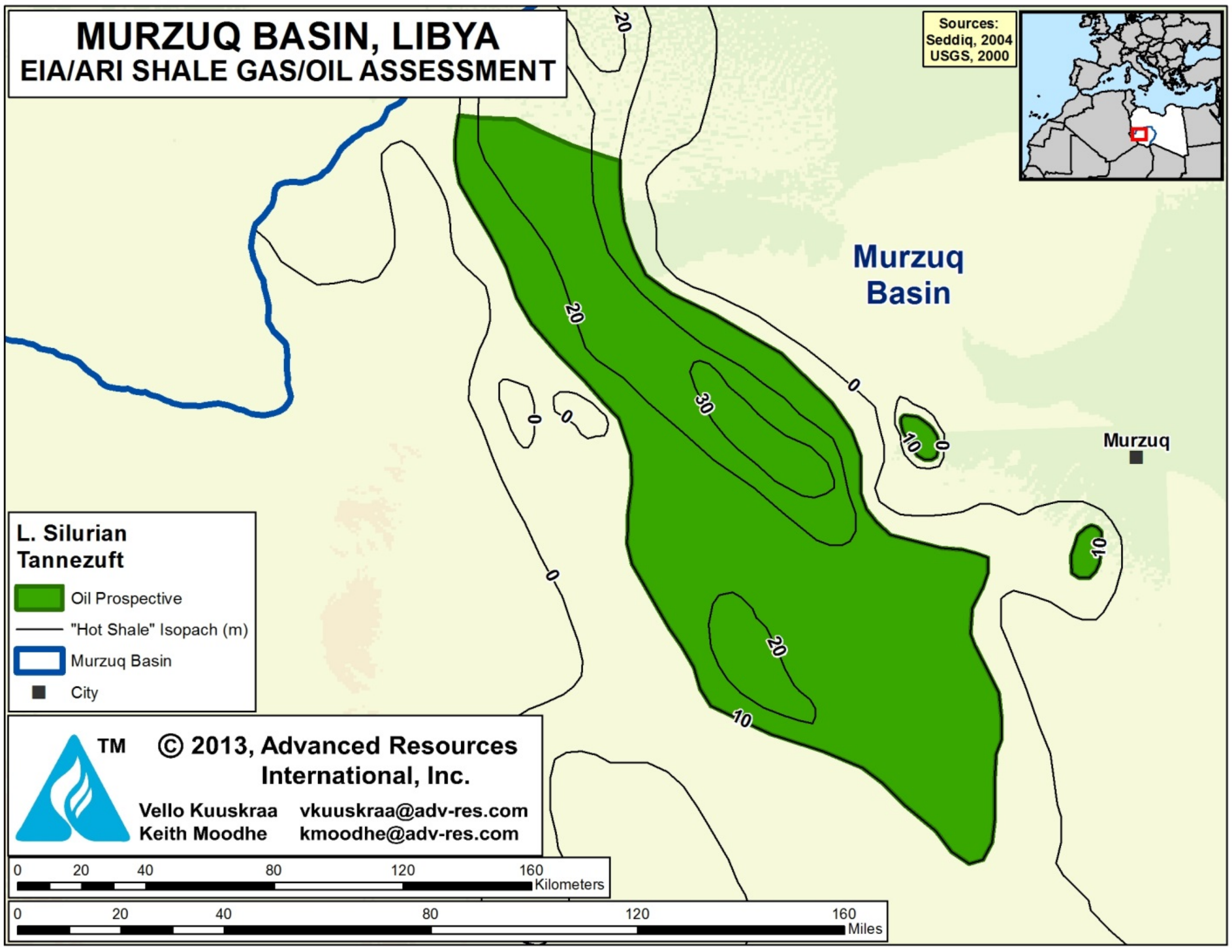
We have mapped a 5,670-mi² oil-prospective area in the center of the Murzuq Basin, Figure XVII-14. The depth of the Tannezuft "hot shale" in the prospective area of the Murzuq Basin ranges from 3,300 ft on the flanks to 10,000 ft in the central part of the basin.[6] The outcrops of the Tannezuft Formation in the uplifts surrounding the basin provide useful information on formation thickness and other properties. While the overall Tannezuft Formation can be up to 1,000 ft thick, only the basal "hot shale" unit, with thickness ranging from 30 to 100 ft has been included in our resource assessment.

Figure XVII-14. Shale Prospective Area of the Murzuq Basin.



Source: ARI, 2013

- In the NC-115 license area, 146 m of core was taken from 22 wells, all of which penetrated the Tannezuft Formation. Here the basal Tannezuft shale serves as both a seal as well as the source rock for the productive Mamuniyat sandstone formation in the license area. In this area, the "hot shale" exists as a north to south belt with limited width, ranging in thickness up to 35 m, with the thickest development in the southeastern portion of the prospective area. The TOC of the "hot shale" ranges from 3.2% to 23.1% (average 9.9%) and the shale has a thermal maturity of R_o 0.83% to 0.95% in well A1-NC115, placing the shale in the late oil maturity window. The maturity of the shale is believed to increase toward the southern portion of the prospective area.[4]

- Core analysis from a second well, F3-NC174, recorded TOC values that ranged from 3.7% to 4.7% (average 4.0%), with thermal maturity of 0.7 R_o.[4]
- A detailed analysis of the E1-NC174 well, drilled in 1997, provides further information on the properties of Tannezuft "hot shale" in the Awabari Trough. The core data shows the presence of Type II (oil prone) kerogen with TOC values of up to 13%. The "hot shale" existed over an interval from 7,244 to 7,267 ft, with leaner but still organic-rich intervals above and below the "hot shale" interval, Figure XVII-15.[7]

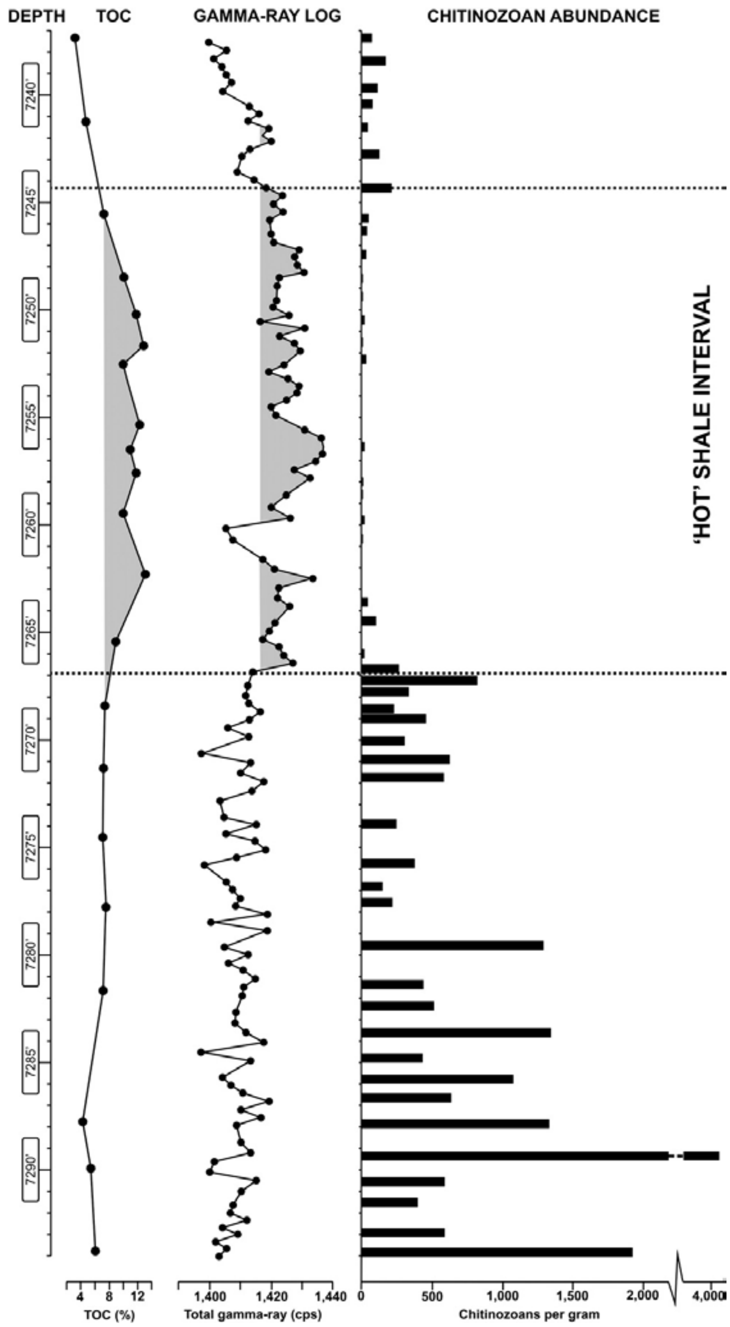
Upper Silurian Tannezuft Shale. An in-depth geochemical investigation was performed recently on a series of representative shale samples from the Upper Silurian Tannezuft Formation of the Murzuq Basin.[5] The purpose of this study was to establish the source rock quality of the extensive Silurian Tannezuft "cool shales" at the top of the Silurian section. (Geochemical analysis of the Upper Silurian Shale in Jordan, as reported in our separate Jordan chapter, indicated the potential for prospective organic-rich shale within the Upper Silurian in addition to the organic-rich shale in the Lower Silurian.)

The rock samples from this upper interval were mainly Type III kerogen (gas prone) with some contribution of mixed Type II and III kerogen (gas/oil prone) from marine/terrigenous sources, Figure XVIII-16.[5] The rock samples showed an early to intermediate stage of thermal maturity with Tmax values of 435° to 445°C, indicating the source rock was in the early to middle oil window (R_o of 0.6% to 0.9%) The organic content of the samples was characterized as poor to fair, with TOC values ranging from 0.4% to 1.28%, indicating a mixed oxic to sub-oxic depositional environment.

While the overall Tannezuft Shale Formation in the Murzuq Basin is on the order of 300 m thick, it appears that only the basal ("hot shale") unit of the Silurian Tannezuft Formation is sufficiently organic-rich to be included in our shale resource assessment.

Devonian Awaynat Wanin Formation. The Middle-Late Devonian Awaynat Wanin Formation is also considered a potential shale source rock in the Murzuq Basin. However, only limited information exists for this unit. To date, only the Silurian Tannezuft-Mamuniyat has been established as an effective petroleum system.[8]

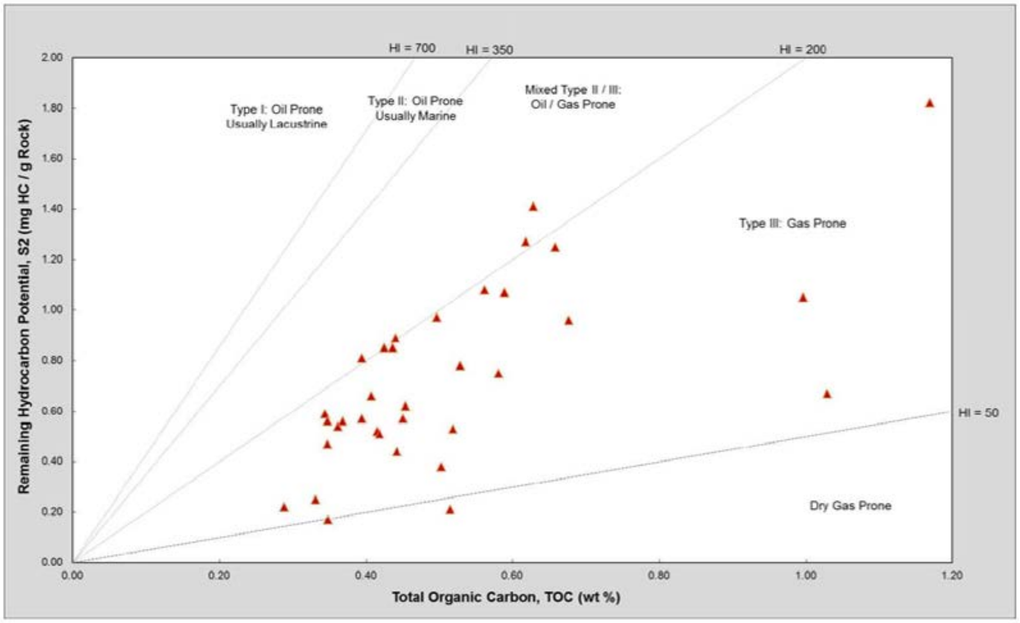
Figure XVII-15. TOC Values within the E1-NC174 Core.
Modified from Luning et al. 2003.



Source: Butcher, 2013.

Figure XVII-16. Cross Plot Between S2 mg HC/g Rock and %TOC for Tannezuft Formation, Field A, NC-115, Murzuq Basin.

Modified from GeoMark Research, LTD (2009).



Source: Hodairi, T. and Philp, P., 2011.

3.3 Resource Assessment

The Tannezuft "hot shale", within the 5,670-mi^2 prospective area of the Murzuq Basin, has a resource concentration of 10 million barrels/mi^2 of oil plus associated gas. The risked shale oil resource in-place is estimated at 27 billion barrels of shale oil plus 19 Tcf of associated shale gas, with 1.3 billion barrels of shale oil and 2 Tcf of associated shale gas as the risked, technically recoverable resource.

4. KUFRA BASIN

Introduction

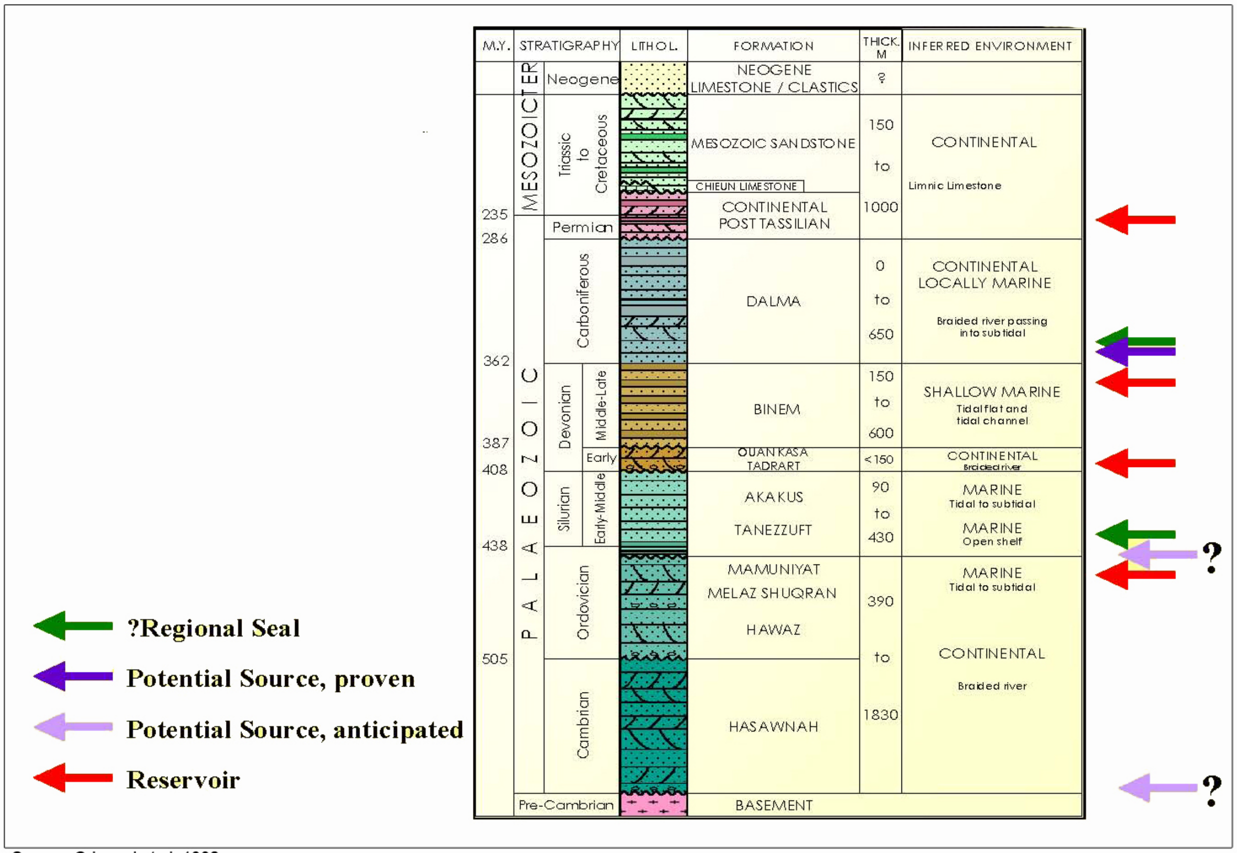
The Kufra Basin is a large 400,000-km^2, remote intra-cratonic sag basin located in southeastern Libya. The Paleozoic structural and deposition history of the Kufra Basin is similar to that of the Murzuq Basin, discussed earlier in this chapter. However, there is considerable uncertainty as to the presence 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 XVII-17.[9] 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.[10]

In addition, the "hot shale" unit was absent in three exploration wells drilled to date, having been replaced by siltstones and sandstones in two dry exploration wells drilled in the northern part of the basin by AGIP in the late 1970s and early 1980s (Bellini, 1991). The absence of lower Silurian shales in these two Kufra Basin exploration wells - - A1-NC-43 and B1-NC43 - - suggests that this area may have been deposited as a sandy delta during the early Silurian, representing the westward continuation of the sandy lower Silurian in western Egypt where the Tannezuft basal "hot shale" is also absent, Figure XVII-18.[10] Since then, one additional exploration well drilled in 1997 has noted the absence of the lower Silurian "hot shale" in the Kufra Basin.

Lower Silurian, organic-rich shales may be present in the western part of the Kufra Basin.[11] However, the areal distribution of this shale unit is laterally highly variable with Silurian basal "hot shale" occurrences deposited as linear features and patches, surrounded by areas in which the basal "hot shale" is absent.[10]

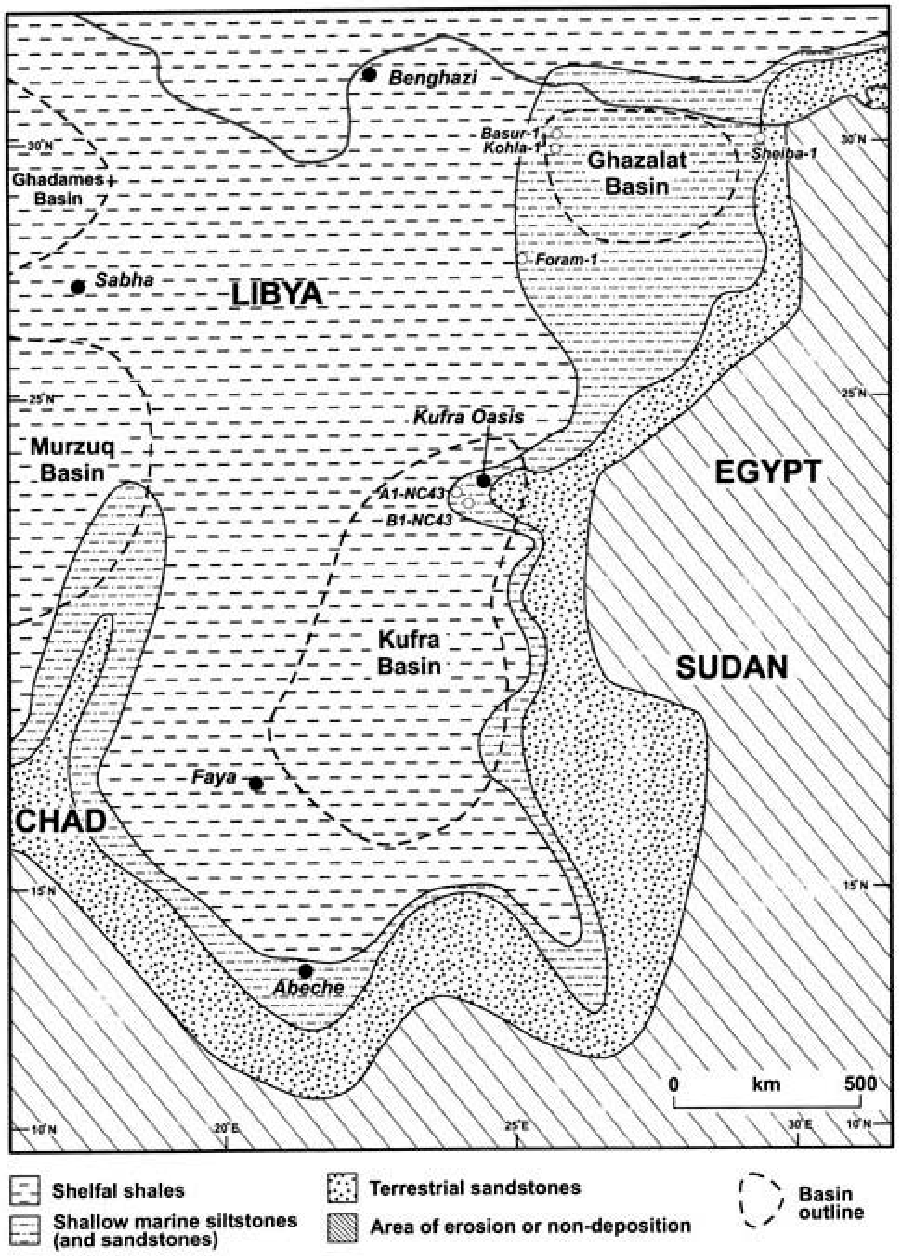
Figure XVII-17. Stratigraphic Column of the Kufra Basin



Source: Grignani et al. 1992

Figure XVII-18. Early Silurian Paleogeography of the Kufra Basin

Based on Keeley, 1989; Semtner et al., 1997; Selley, 1997b; Keeley & Masoud, 1998 and Luning, 1999.



Source: Luning et al. 1999

RECENT ACTIVITY

Libya's oil and gas exploration, including the assessment of its shale oil and gas resources came to a halt during the uprising that overthrew the government of Muammar Gaddafi. However, in late 2012, the Chairman of Libya's National Oil Company, Mr. Nuri Berruien, announced that the company is examining options for exploring its unconventional oil and gas resources. One option discussed by Chairman Berruien is to internally evaluate the unconventional resources and then bring in international companies with expertise in unconventional resource exploration and development.[12]

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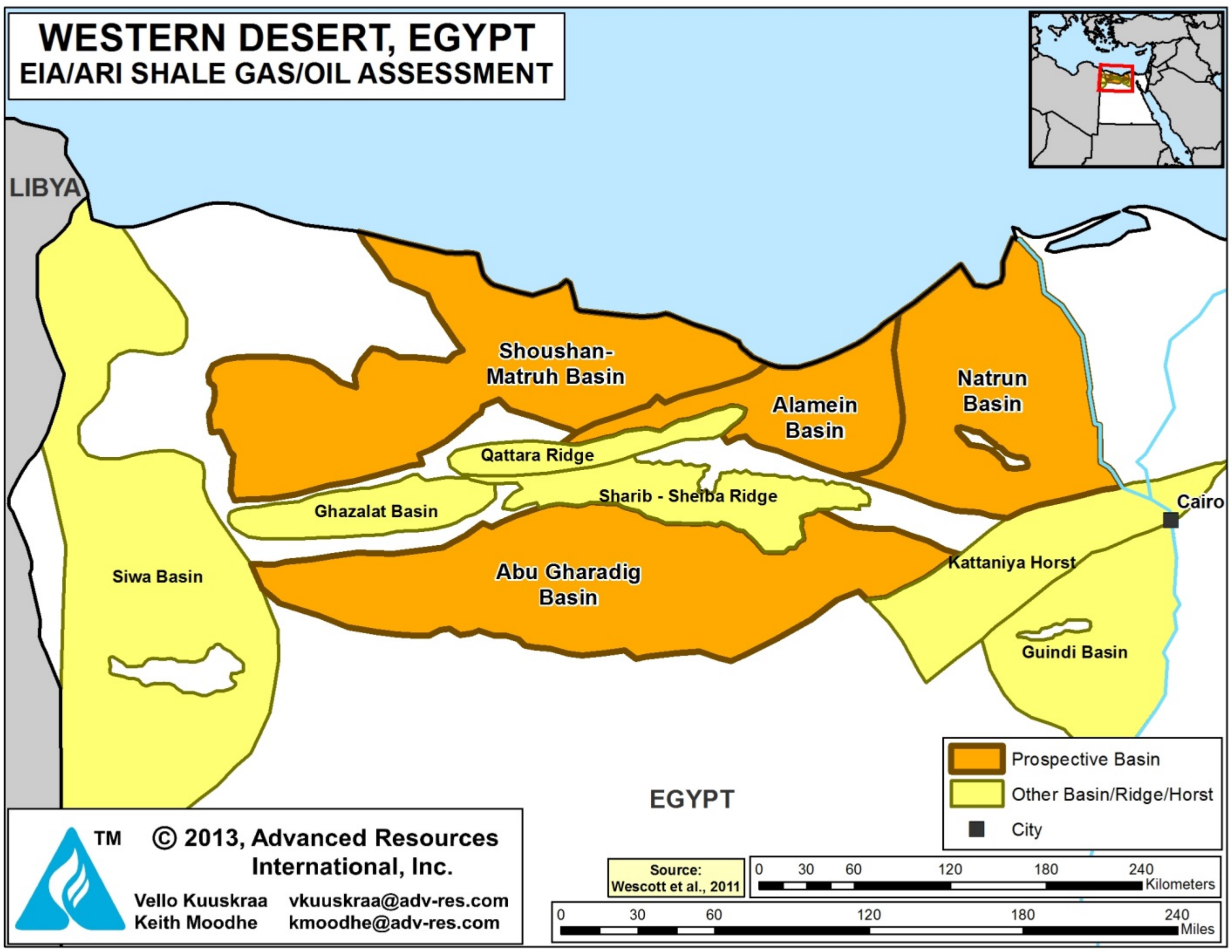
XVIII. EGYPT

SUMMARY

Egypt has four basins in the Western Desert with potential for shale gas and shale oil - - Abu Gharadig, Alamein, Natrun and Shoushan-Matruh, Figure XVIII-1.[1] The target horizon is the organic-rich Khatatba Shale, sometimes referred to as the Kabrit Shale or Safa Shale, within the larger Middle Jurassic Khatatba Formation.

Figure XVIII-1. Hydrocarbon Basins of the Western Desert, Egypt



Source: ARI, 2013.

Our assessment is that the Khatatba Shale contains approximately 535 Tcf of risked shale gas in-place, with 100 Tcf of risked, technically recoverable shale gas resources, Table XVIII-1. In addition, we estimate that the Khatatba Shale contains about 114 billion barrels of risked shale oil in-place, with 4.6 billion barrels of risked, technically recoverable shale oil resources, Table XVIII-2.

Table XVIII-1. Shale Gas Reservoir Properties and Resources of Egypt

			Abu Gharadig	Alamein	Natrun	Shoushan-Matruh
Basic Data	Basin/Gross Area		(7,670 mi^2)	(2,340 mi^2)	(4,860 mi^2)	(7,080 mi^2)
	Shale Formation		Khatatba	Khatatba	Khatatba	Khatatba
	Geologic Age		M. Jurassic	M. Jurassic	M. Jurassic	M. Jurassic
	Depositional Environment		Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		6,840	2,340	4,860	4,420
	Thickness (ft)	Organically Rich	1,500	1,000	1,200	1,000
		Net	300	200	240	200
	Depth (ft)	Interval	11,000 - 13,000	13,000 - 15,000	13,000 - 15,000	10,000 - 15,000
		Average	12,000	14,000	14,000	13,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		4.0%	4.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		1.15%	0.85%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Wet Gas	Assoc. Gas	Assoc. Gas	Wet Gas
	GIP Concentration (Bcf/mi^2)		99.2	29.1	35.0	71.3
	Risked GIP (Tcf)		325.7	16.7	41.6	151.2
	Risked Recoverable (Tcf)		65.1	1.3	3.3	30.2

Table XVIII-2. Shale Oil Reservoir Properties and Resources of Egypt

			Abu Gharadig	Alamein	Natrun	Shoushan-Matruh
Basic Data	Basin/Gross Area		(7,670 mi^2)	(2,340 mi^2)	(4,860 mi^2)	(7,080 mi^2)
	Shale Formation		Khatatba	Khatatba	Khatatba	Khatatba
	Geologic Age		M. Jurassic	M. Jurassic	M. Jurassic	M. Jurassic
	Depositional Environment		Marine	Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		6,840	2,340	4,860	4,420
	Thickness (ft)	Organically Rich	1,500	1,000	1,200	1,000
		Net	300	200	240	200
	Depth (ft)	Interval	11,000 - 13,000	13,000 - 15,000	13,000 - 15,000	10,000 - 15,000
		Average	12,000	14,000	14,000	13,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		4.0%	4.0%	4.0%	4.0%
	Thermal Maturity (% Ro)		1.15%	0.85%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Oil Phase		Condensate	Oil	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		14.3	25.1	30.1	7.9
	Risked OIP (B bbl)		47.1	14.4	35.9	16.8
	Risked Recoverable (B bbl)		1.88	0.58	1.43	0.67

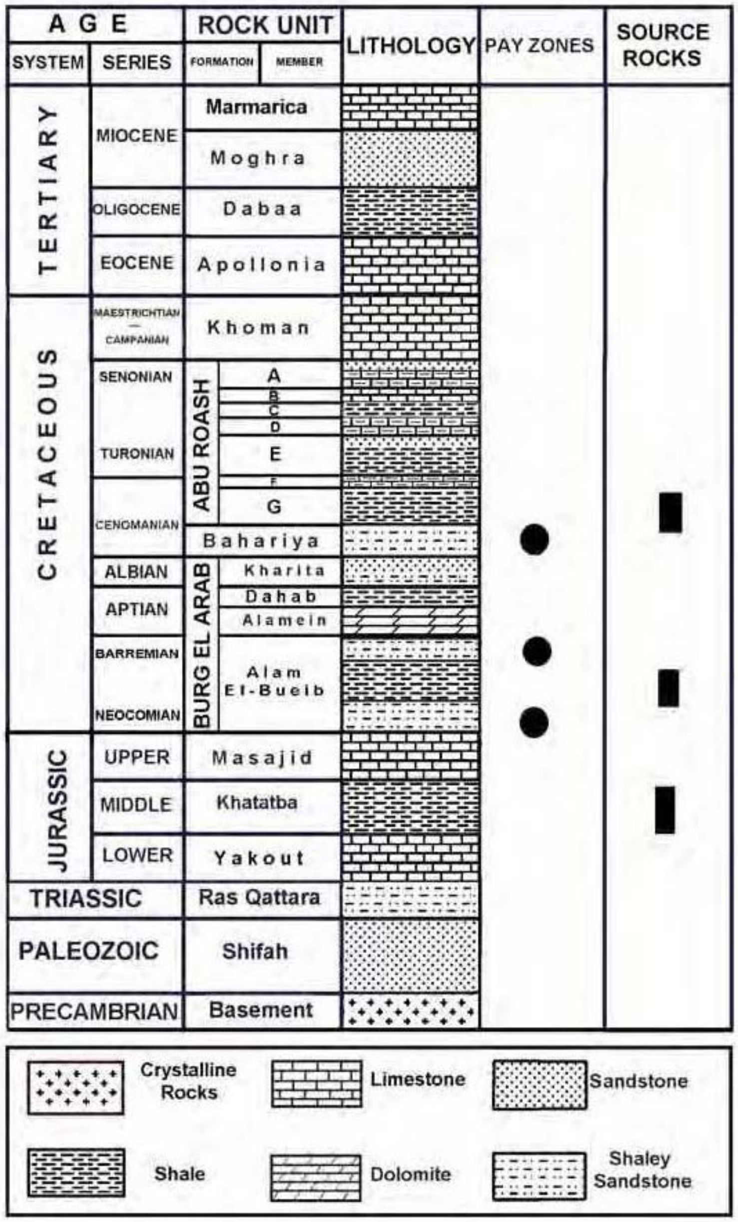
INTRODUCTION

The northern portion of the Western Desert of Egypt contains a series of basins underlain by organic-rich shales that have provided the source for the conventional hydrocarbons production from these basins. The primary hydrocarbon basins in the Western Desert include Abu Gharadig, Alamein, Natrun and Shoushan-Matruh. The Western Desert is the location of many of the major oil and gas fields of Egypt, including the more recently discovered, large Jurassic fields of Kanayes (discovered in 1992), Obayeid (discovered in 1993) and Shams (discovered in 1997).[2]

The basins have a thick sedimentary sequence comprising Paleozoic through Tertiary strata that exceed 15,000 feet, Figure XVIII-2.[3] Despite many years of successful discovery of conventional oil and gas deposits, the large Western Desert hydrocarbon basins of Egypt are still only lightly explored, particularly for their deeper formations.

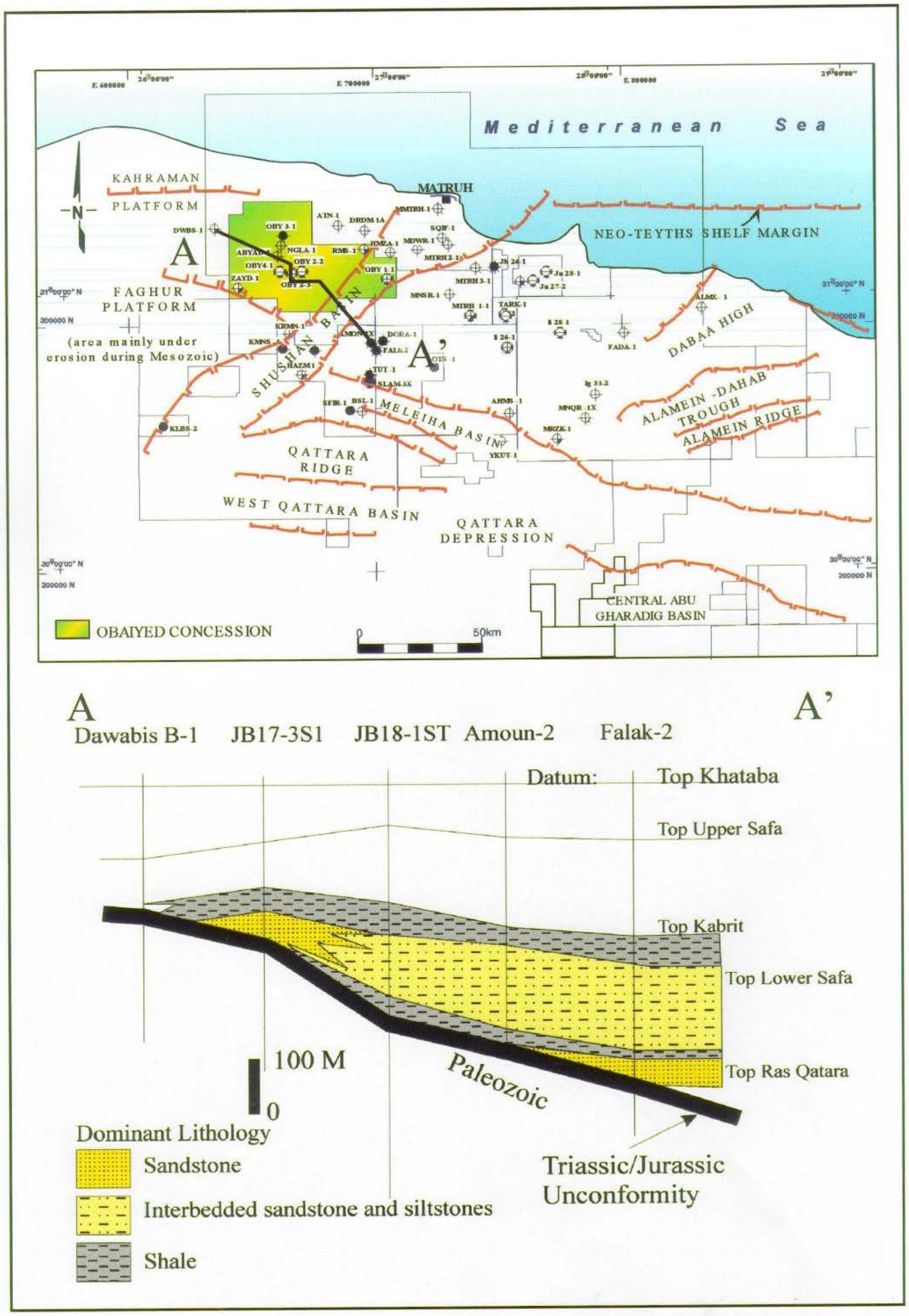
The focus of our shale resource study is the Khatatba Shale within the Middle Jurassic Khatatba Formation, also called the Kabrit Shale and the Safa Shale, Figure XVIII-3.[4]

Figure XVIII-2. Generalized Lithostratigraphic Column of the Western Desert of Egypt.



Source: Younes, 2012 (Modified after Abdou,1998).

Figure XVIII-3. Khatatba Formation and Kabrit (Safa) Shale, Shoushan-Matruh Basin, Western Desert.



Source: Dolson, 2000.

Egypt's geologic history is complex and a full discussion of its geology and tectonics is beyond the scope of this resource assessment. However, this chapter provides an overview that is intended to help place the shale oil and gas resources of the Western Desert into context. As such, the study examined three major shale source rocks in the Western Desert of Egypt before establishing the Middle Jurassic Khatatba Shale as the primary target.

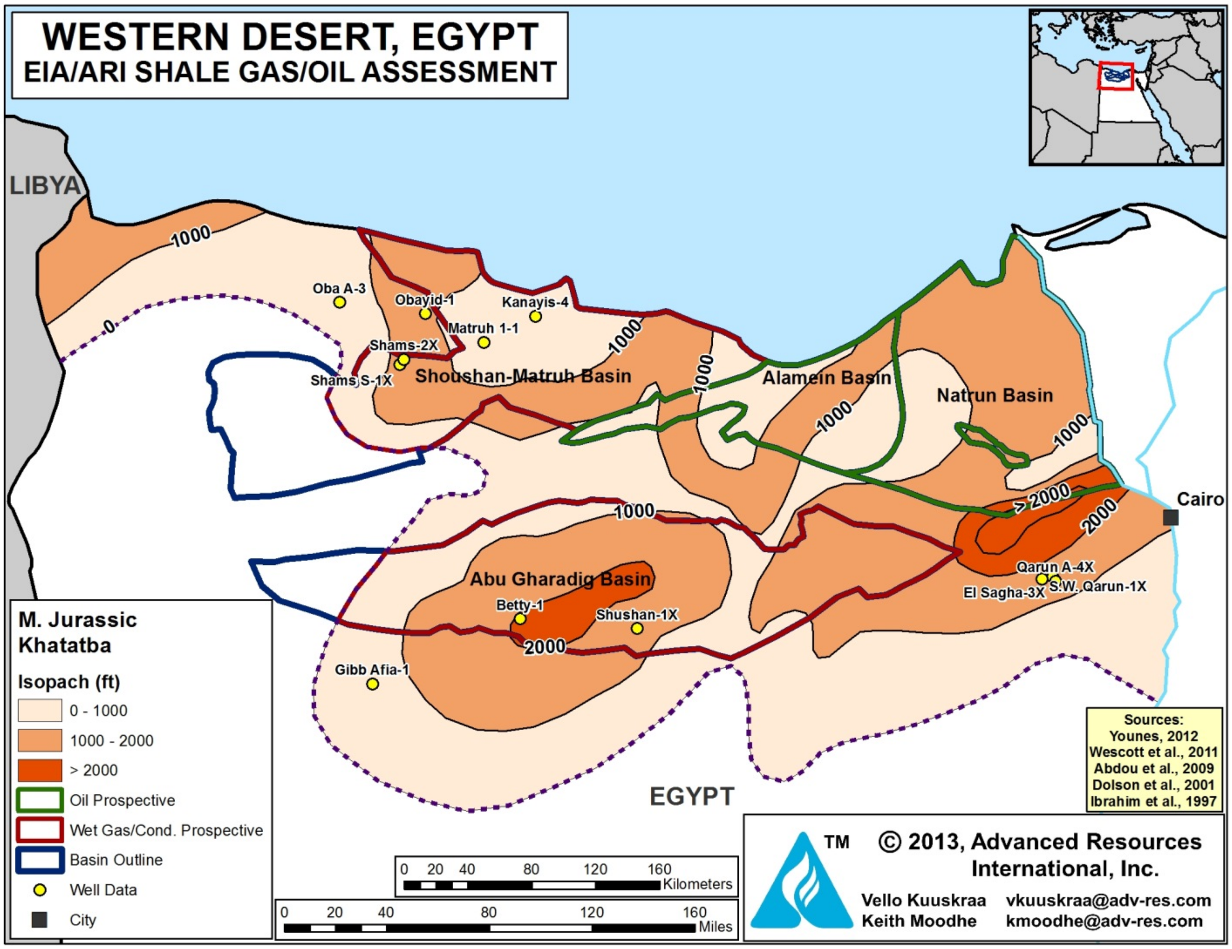
Silurian. A thick sequence of Silurian siltstone, estimated at about 200 to 300 m in the Basur-1 and Kohka-1 wells, exists in the northwestern portion of the Western Desert.[5] These sandstones and siltstones thin to the south and east as shown by the Foram-1 and Sheiba-1 wells.[6] The sandstone and siltstone units appear to rest directly on Upper Ordovician glacial deposits without any evidence of Silurian organic-rich shales.[8] The Western Desert of Egypt lacks a Silurian Tannezuft ("Hot Shale") source rock equivalent due to a paleo-basement high and erosion of Silurian sediments.[7]

Cretaceous. Cretaceous-age shale source rocks within the Alam El-Bueib and Abu Roash formations exist across much of the Western Desert. However, these shales have been classified as marginal to moderate source rock quality for oil and gas generation, with TOC values generally reported at less than 2%. In addition, the Cretaceous-age source rocks are thermally immature in significant portions of the Western Basin study area.[8] Due to these less favorable reservoir properties and limited data, we have not included these Cretaceous-age source rocks in our shale oil and gas resource assessment.

Jurassic. During the late Triassic and Jurassic, a series of rift basins formed in the Western Desert. These rift basins and their subsequent extension during the Cretaceous provided the setting for the important Khatatba Formation and its thick, black shale deposition. The Khatatba Shale (also called the Safa Shale) has served as the source rock for much of the oil and gas found in the Western Desert.[2,3]

The larger Khatatba Formation ranges from 1,000 feet to over 2,000 feet thick in the Western Desert. The type section of the Kabrit (Safa) Shale Member within the Khatatba Formation ranges in thickness from 0 to over 600 feet in the Western Desert, with an estimated net pay of 200 to 300 feet, XVIII-Figure 4.[3,9,2,10]

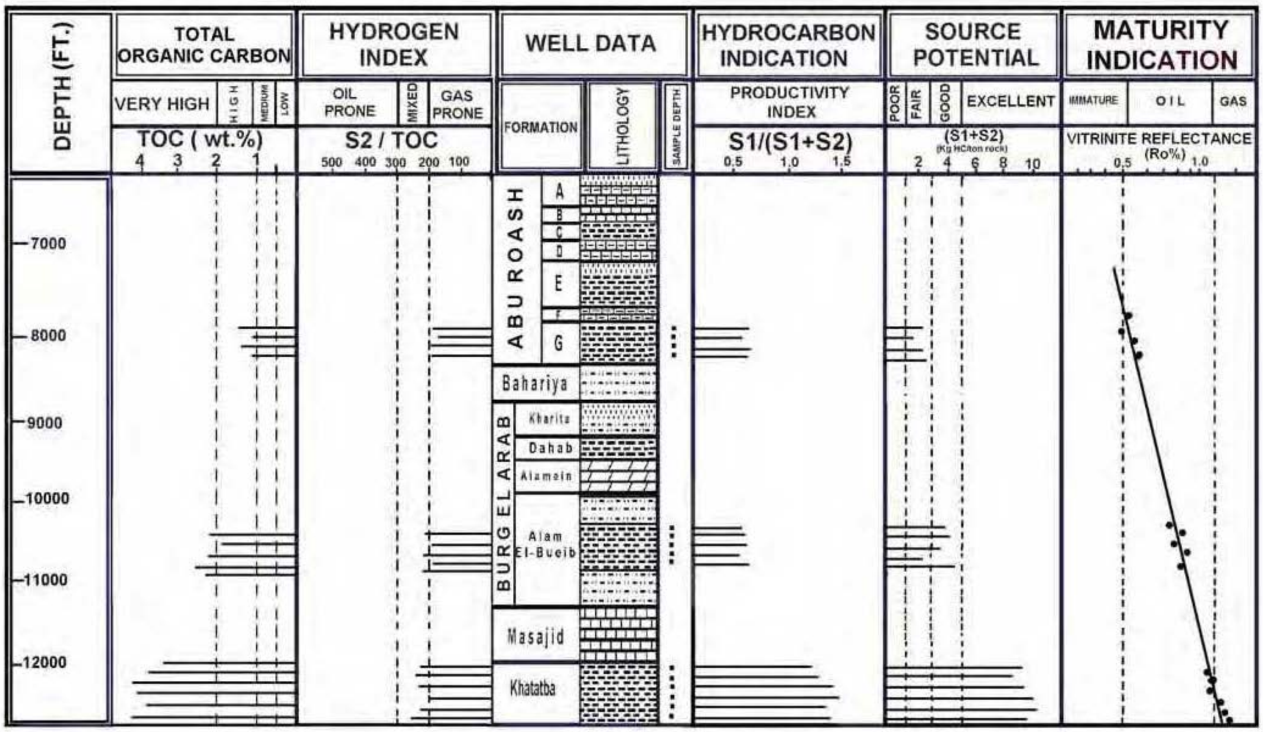
Figure XVIII-4. Middle Jurassic Khatatba Formation Gross Isopach



Source: ARI, 2013.

Detailed source rock evaluations of core samples from the Shushan-1X well in the southern portion of the Abu Gharadig Basin provided important data on the reservoir properties of the Khatatba Shale. The TOC of the shale varied from 3.6% to 4.2% with a vitrinite reflectance (R_o) of 1.0% to 1.3%, placing the shale primarily in the wet gas and condensate window, Figure XVIII-5.[3] The shale contains mixed vitrinite-inertinite kerogen derived from land plants and algae, implying a mixture of marginal marine and continental organic matter.[11] The combination of maximum temperature and kerogen type places the Khatatba Shale primarily in the wet gas/condensate and volatile oil windows with significant associated plus free gas in the pore space.

Figure XVIII-5. TOC and Maturity Data, Jurassic- and Cretaceous-Age Source Rocks, Western Desert, Egypt



Source: Younes, 2012

ABU GHARADIG BASIN

Geologic Setting. The 7,670-mi^2 Abu Gharadig Basin is an east-west trending half graben with a depth to basement that exceeds 30,000 feet. The basin is bounded on the north by the Qattara Ridge and on the south by the Sitra Platform. The Jurassic-age Khatatba Shale is considered the major hydrocarbon source rock in this basin.[2] We have identified a 6,840-mi^2 prospective area in this basin after excluding the western portion of the basin which lacks Middle Jurassic deposits, Figure XVIII-4.

Reservoir Properties (Prospective Area). Within the 6,840-mi^2 prospective area, the depth of the Khatatba Shale in the Abu Gharadig Basin ranges from 11,000 to 13,000 feet, averaging 12,000 feet. The gross interval of the Khatatba Formation ranges from near 0 to over 2,000 feet, averaging about 1,500 feet thick. The net shale, using a net to gross ratio of 0.2, is estimated at 300 feet. Based on grain and bulk density data from the Betty-1 well, drilled in the south central portion of the basin, the porosity ranges from 2.4% to 8.4%, averaging 5.7% for six core samples. The TOC of the shale, using data from the Shushan-1X well, ranges from 3.6% to 4.2%, averaging 4%, with thermal maturity (Ro) values of 1.0% to 1.3%.

Resource Assessment. Within the 6,840-mi^2 prospective area of the Abu Gharadig Basin, the Khatatba Shale has a resource concentration of 99 Bcf of wet gas and 14 million barrels of oil/condensate per mi^2. The risked resource in-place for wet gas in the prospective area is estimated at 326 Tcf, with 65 Tcf as the risked, technically recoverable shale gas resource, Table XVIII-1. The risked resource in-place for oil/condensate in the prospective area is estimated at 47 billion barrels with 1.9 billion barrels of the risked, technically recoverable shale oil resource, Table XVIII-2.

ALAMEIN BASIN

Geologic Setting. The Alamein Basin is a large Jurassic rift basin in the northwestern portion of the Western Desert which was further extended during the Cretaceous. The onshore portion of the basin is bounded on the north by the Mediterranean Sea and on the south by the Qattara Ridge. The Jurassic-age Khatatba Shale, which contains mixed Type II and III kerogen, appears to be the main shale oil and gas target in this basin. Remarkably, the entire basin appears to be prospective for the Khatatba Shale.

Reservoir Properties (Prospective Area). Within the 2,340-mi^2 prospective area, the depth of the Khatatba Shale in the Alamein Basin ranges from 13,000 to 15,000 feet, averaging 14,000 feet. The gross interval of the Khatatba Formation averages 1,000 feet with a porosity of 5.7%. Organic content ranges up to 10%, with an average of 4%, and the shale is in the oil thermal maturity window (R_o of 0.8% to 1.0%).[12]

Resource Assessment. Within the 2,340-mi^2 prospective area of the Alamein Basin, the Khatatba Shale has a resource concentration of 25.1 million barrels of oil/condensate per mi^2 plus associated gas. The risked resource in-place for oil/condensate in the prospective area is estimated at 14 billion barrels, with 0.6 billion barrels as the risked, technically recoverable resource, Table XVIII-2. The basin also has associated gas estimated at 17 Tcf of risked in-place, with about 1 Tcf as risked technically recoverable, Table XVIII-1.

NATRUN BASIN

Geologic Setting. The Natrun Basin, covering an area of 4,860 mi^2, is a poorly defined basin located between the major oil and gas fields of the Nile Delta and the Western Desert.[13] The basin is bounded on the north by the Mediterranean Sea and on the south by the Kattaniya Horst. The Natrun Basin appears to hold a favorable conventional petroleum system of source rock, reservoir-seal, and timing of thermal maturity. The Jurassic-age Khatatba Shale is considered the major hydrocarbon source rock in this basin.[2] The entire basin appears to be prospective for the Middle Jurassic Khatatba Shale, Figure XVIII-4.

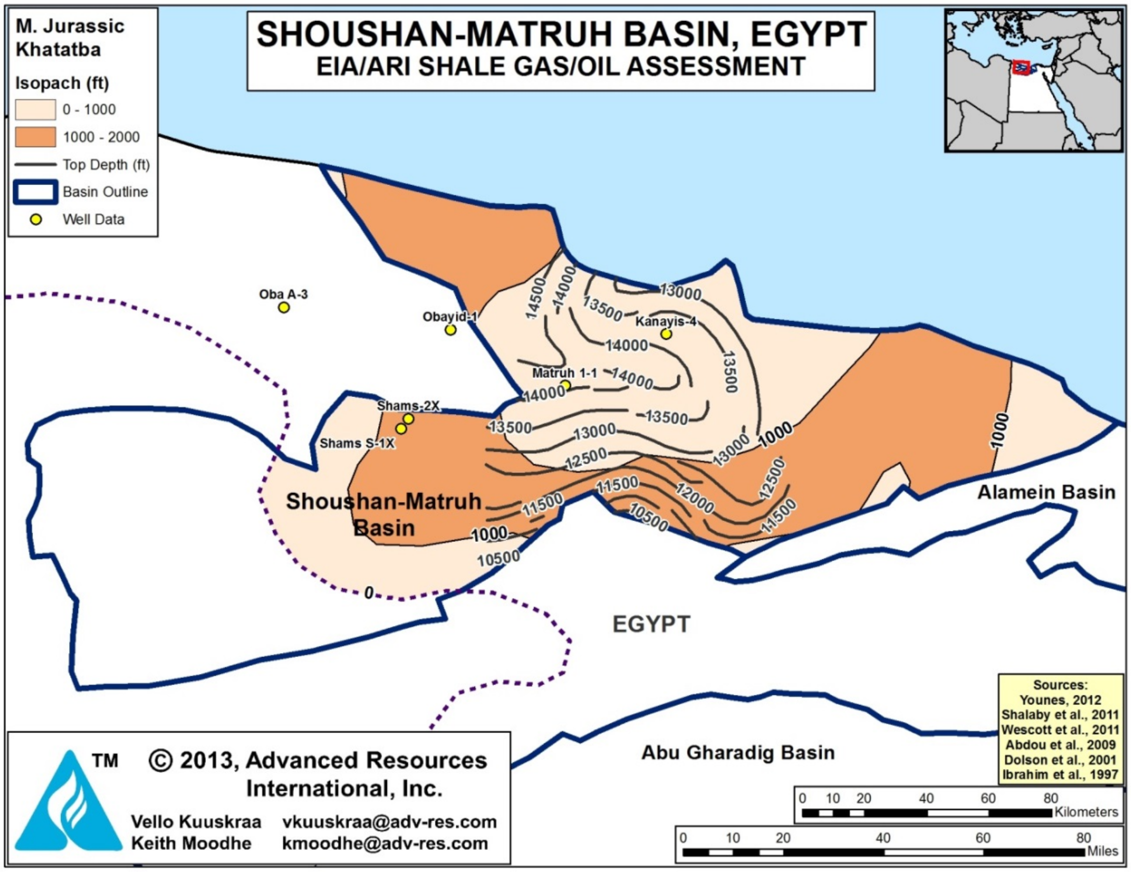
Reservoir Properties (Prospective Area). Within the 4,860-mi^2 prospective area, the depth of the Khatatba Shale in the Natrun Basin ranges from 13,000 to 15,000 ft, averaging 14,000 ft. The gross interval of the Khatatba Formation ranges from near 0 to over 2,000 ft, averaging about 1,200 ft thick. The net shale, using a net to gross ratio of 0.2, is estimated at 240 ft, with a porosity averaging 5.7%. The TOC averages 4% with thermal maturity (R_o) values of 0.7% to 1.0%, placing the shale in the oil window. (Although thermal modeled vitrinite reflectance values indicated over-mature Jurassic source rocks, borehole data from intra-basinal sediments showed a thermal maturity in the oil window).**Error! Bookmark not defined.**

Resource Assessment. Within the 4,860-mi^2 prospective area of the Natrun Basin, the Khatatba Shale has a resource concentration of 30.1 million barrels of oil/condensate per mi^2. The risked resource in-place for oil/condensate in the prospective area is estimated at 36 billion barrels, with 1.4 billion barrels as the risked, technically recoverable resource, Table XVIII-2. The basin also has associated gas estimated at 42 Tcf of risked in-place, with 3 Tcf of risked technically recoverable resources, Table XVIII-1.

SHOUSHAN-MATRUH BASIN

Geologic Setting. The Shoushan-Matruh Basin is a large Jurassic rift basin in the northwestern portion of the Western Desert which also was further extended during the Cretaceous. The basin is bounded on the north by the Mediterranean Sea and on the south by the Qattara Ridge. The Jurassic-age Khatatba Shale is the focus of our shale oil and gas resource assessment in this basin. We have identified a prospective area of 4,420 mi^2 in this basin after deleting the western portion of the basin beyond the limits of Middle Jurassic deposition, Figure XVIII-6.[3,14,1,9,2,10]

Figure XVIII-6. Shoushan-Matruh Basin, Khatatba Shales Depth and Gross Isopach



Source: ARI, 2013.

Reservoir Properties (Prospective Area). Within the 4,420-mi^2 prospective area, the depth of the Khatatba Shale in the Shoushan-Matruh Basin ranges from 10,000 to 15,000 ft, averaging 13,000 ft. The gross interval of the Khatatba Formation ranges from near zero to over 1,500 ft averaging 1,000 ft. The Khatatba Shale has an organic content averaging 4% and a thermal maturity of R_o 1.0% to 1.3%, placing the shale in the wet gas/condensate window. Core analysis indicates a porosity of about 5.7%.

Resource Assessment. Within the 4,420-mi^2 prospective area of the Shoushan-Matruh Basin, the Khatatba Shale has a resource concentration of 71 Bcf of wet gas and 7.9 million barrels of oil/condensate per mi^2. The risked resource in-place for wet gas in the prospective area is estimated at 151 Tcf, with 30 Tcf as the risked technically recoverable resource, Table XVIII-1. The risked resource in-place for oil/condensate in the prospective area is estimated at 17 billion barrels, with 0.7 billion barrels as the risked, technically recoverable resource, Table XVIII-2.

RECENT ACTIVITY

Much of the past exploration drilling in the Western Desert has targeted the Cretaceous and shallower sediments. Recently, however, Apache has begun to successfully explore the deeper Jurassic sediments, such as the Safa Sandstone in the Faghur Basin of the Western Desert. In 2010, Apache announced that an unidentified shale formation below the East Bahariya Field holds "between 700 million and 2.2 billion barrels of oil". The company stated that, "We have two wells planned to test the idea here later this year."[15] However, no further information is publically available as to activity or results involving the exploration for oil from these shales.

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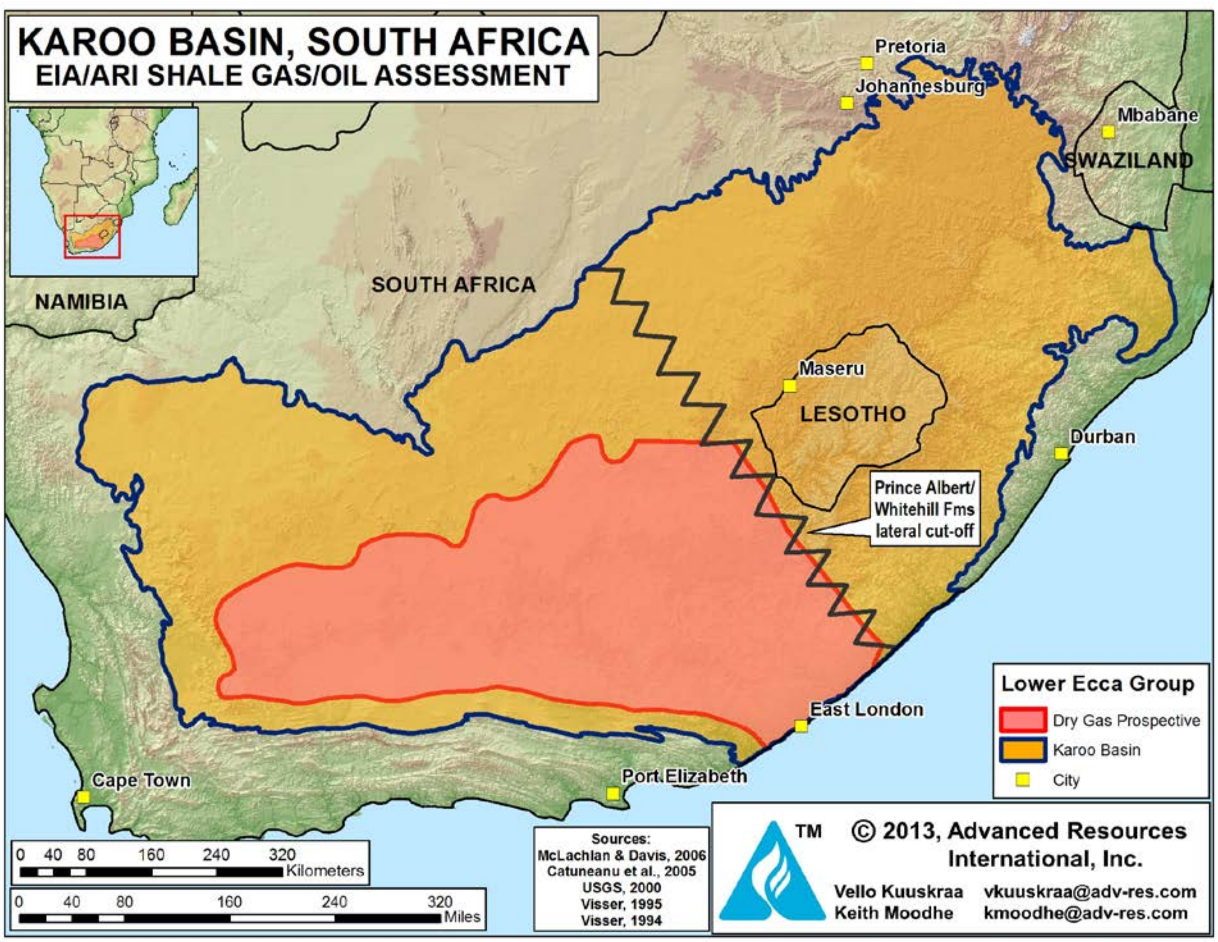
XIX. SOUTH AFRICA

SUMMARY

South Africa has one major sedimentary basin that contains thick, organic-rich shales - - the Karoo Basin in central and southern South Africa, Figure XIX-1.[1,2,3] The Karoo Basin is large (236,400 mi^2), extending across nearly two-thirds of the country, with the southern portion of the basin potentially favorable for shale gas. However, the basin contains significant areas of igneous (sill) intrusions that may impact the quality of the shale resources, limit the use of seismic imaging, and increase the risks of shale exploration.

Figure XIX -1: Outline of Karoo Basin and Prospective Shale Gas Area of South Africa



Source: ARI, 2013.

The Permian-age Ecca Group, with its organic-rich source rocks in the Lower Ecca Formation, is the primary shale formation addressed by this assessment. Of particular interest is the organic-rich, thermally mature black shale unit in the Whitehill Formation of the Lower Ecca. This shale unit is regionally persistent in composition and thickness and can be traced across most of the southern portion of the Karoo Basin.[4]

We estimate that the Lower Permian Ecca Group shales in this basin contain 1,559 Tcf of risked shale gas in-place, with 370 Tcf as the risked, technically recoverable shale gas resource, Table XIX-1. We have excluded the Upper Ecca shales in this basin from quantitative assessment because their TOC content is reported to be below the 2% TOC standard used by this resource assessment study.

Table XIX-1: Shale Gas Reservoir Properties and Resources of the Karoo Basin

Basic Data	Basin/Gross Area		Karoo ($236,400 mi^2$)		
	Shale Formation		Prince Albert	Whitehill	Collingham
	Geologic Age		L. Permian	L. Permian	L. Permian
	Depositional Environment		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		60,180	60,180	60,180
	Thickness (ft)	Organically Rich	400	200	200
		Net	120	100	80
	Depth (ft)	Interval	6,000 - 10,500	5,500 - 10,000	5,200 - 9,700
		Average	8,500	8,000	7,800
Reservoir Properties	Reservoir Pressure		Mod. Overpress.	Mod. Overpress.	Mod. Overpress.
	Average TOC (wt. %)		2.5%	6.0%	4.0%
	Thermal Maturity (% Ro)		3.00%	3.00%	3.00%
	Clay Content		Low	Low	Low
Resource	Gas Phase		Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		42.7	58.5	36.3
	Risked GIP (Tcf)		385.3	845.4	327.9
	Risked Recoverable (Tcf)		96.3	211.3	82.0

INTRODUCTION

South Africa is a net natural gas importer, primarily from neighboring Mozambique and Namibia. As such, South Africa has given priority to exploration for domestic gas and oil. Shale exploration is initiated via a Technical Cooperation Permit (TCP), which may lead to an Exploration Permit (EP) and eventually to a production contract. The country has a corporation tax of 28% and royalty of 7%, terms that are favorable for gas and oil development.

A number of major and independent companies have signed Technical Cooperation Permits (TCPs) to pursue shale gas in the Karoo Basin, including Royal Dutch Shell, the Falcon Oil & Gas/Chevron joint venture, the Sasol/Chesapeake/Statoil joint venture, Sunset Energy Ltd. of Australia and Anglo Coal of South Africa.

1. KAROO BASIN

1.1 Introduction

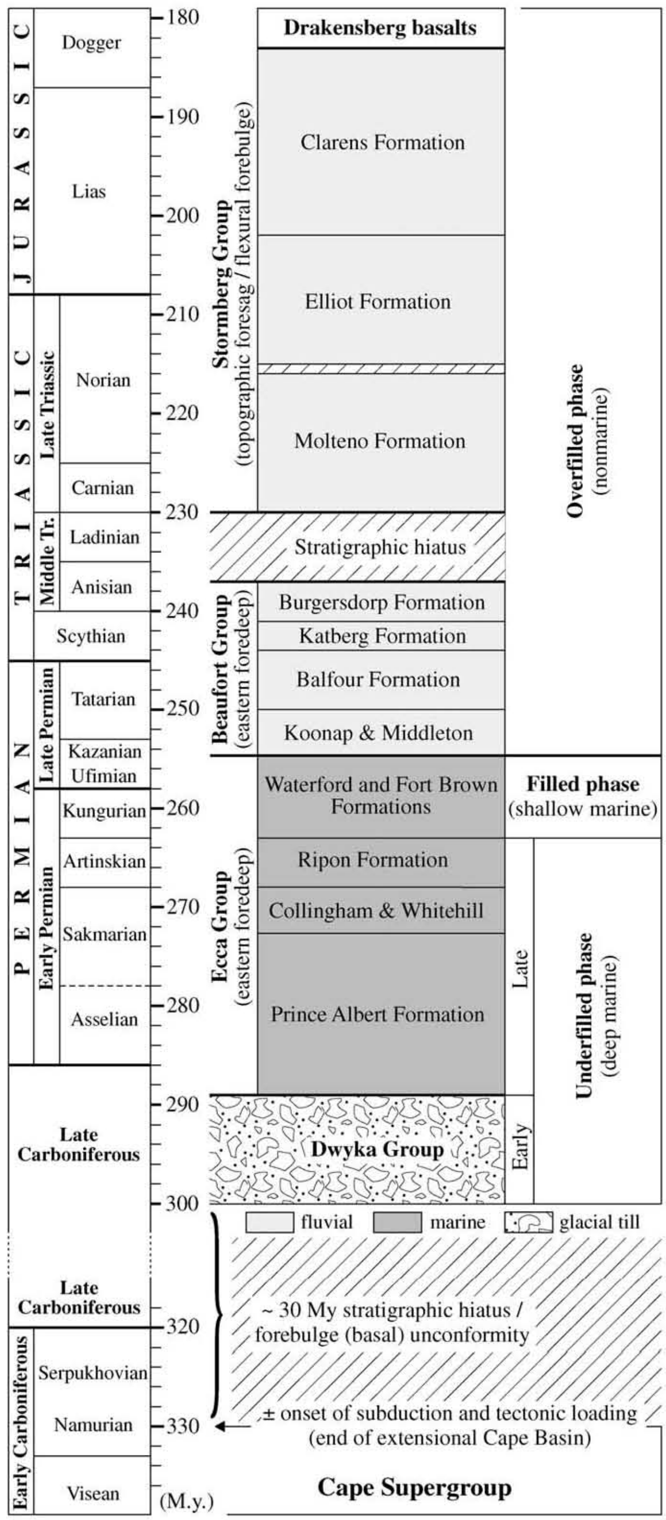
The Karoo foreland basin is filled with over 5 km of Carboniferous to Early Jurassic sedimentary strata. The Early Permian-age Ecca Group underlies much of the Karoo Basin, cropping out along the southern and western basin margins, Figure XIX-1. The Ecca Group contains a sequence of organic-rich mudstone, siltstone, sandstone and minor conglomerates.[5]

1.2 Geologic Setting

The larger Ecca Group, encompassing an interval up to 10,000 ft thick in the southern portion of the basin, is further divided into the Upper Ecca (containing the Fort Brown and Waterford Formations) and the Lower Ecca (containing the Prince Albert, Whitehill and Collingham Formations), Figure XIX-2. The three Lower Ecca formations are the subject of this shale resource assessment.

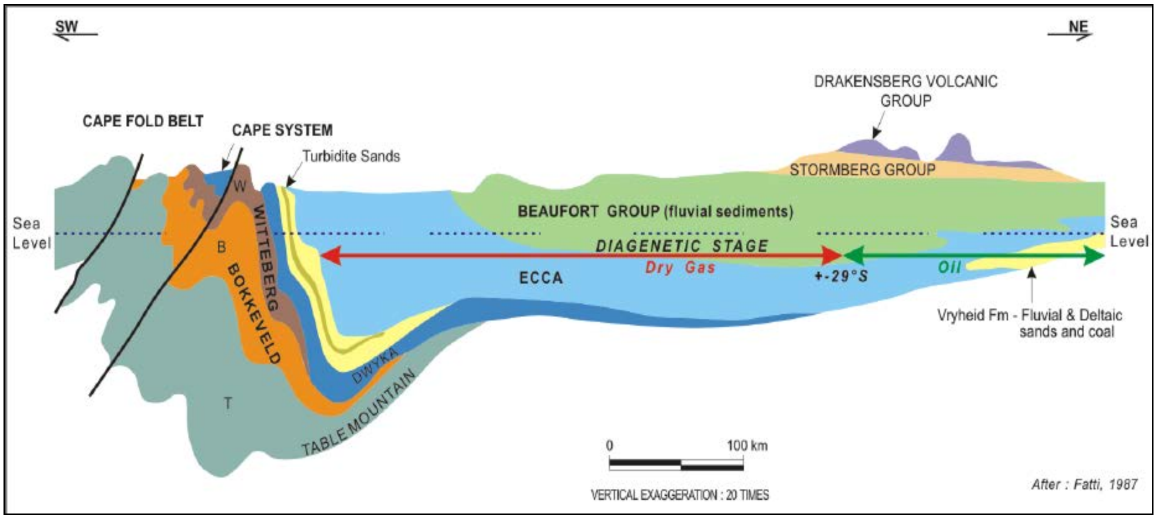
The regional southwest to northeast cross-section illustrates the structure of the Cape Fold Belt of the Ecca Group on the south and the thermal maturity for the Ecca Group on the north, Figure XIX-3.[6]

Figure XIX-2. Stratigraphic Column of the Karoo Basin of South Africa



Source: Catuneanu, O. et al., 2005.

Figure XIX-3. Schematic Cross-Section of Southern Karoo Basin and Ecca Group Shales

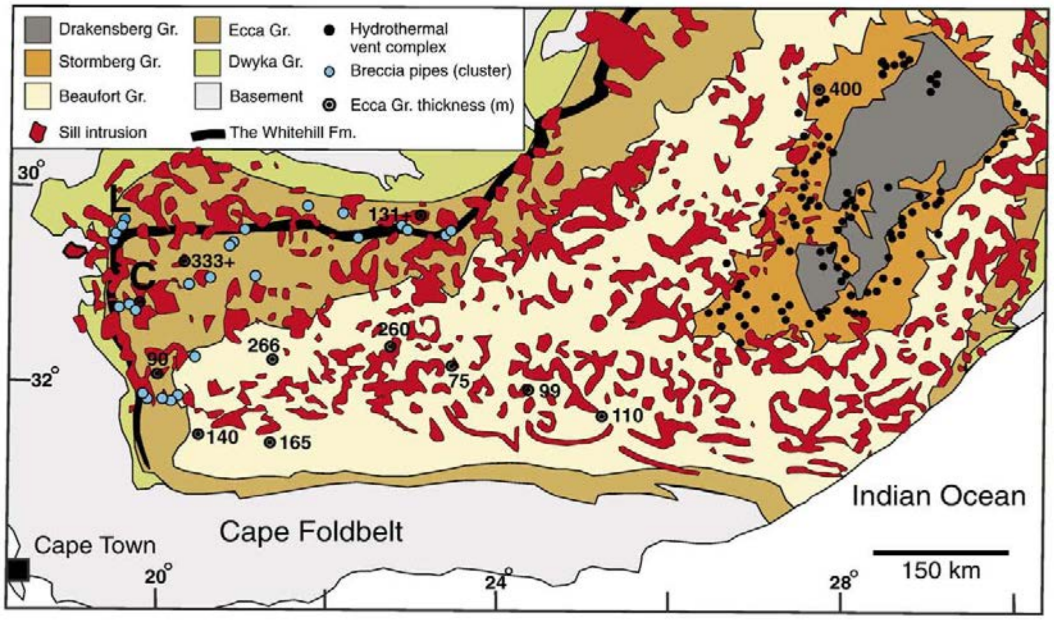


Source: McLachlan, I. and Davis, A., 2006.

Major portions of the Karoo Basin have igneous (sill) intrusions and complex geology, with the most extensive and thickest sills concentrated within the Upper Ecca and Balfour formations.[7] This unusual condition creates significant exploration risk in pursuing the shale resources in the Karoo Basin, Figure XIX-4.[8] (Note that this map reflects the maximum extent of intrusions, which are expected to be less within the target shale formations.) Local mapping indicates that contact metamorphism is restricted to quite close to the intrusions. As such, we removed 15% of the prospective area to account for the potential impact of igneous intrusions and significantly risked the remaining resource.

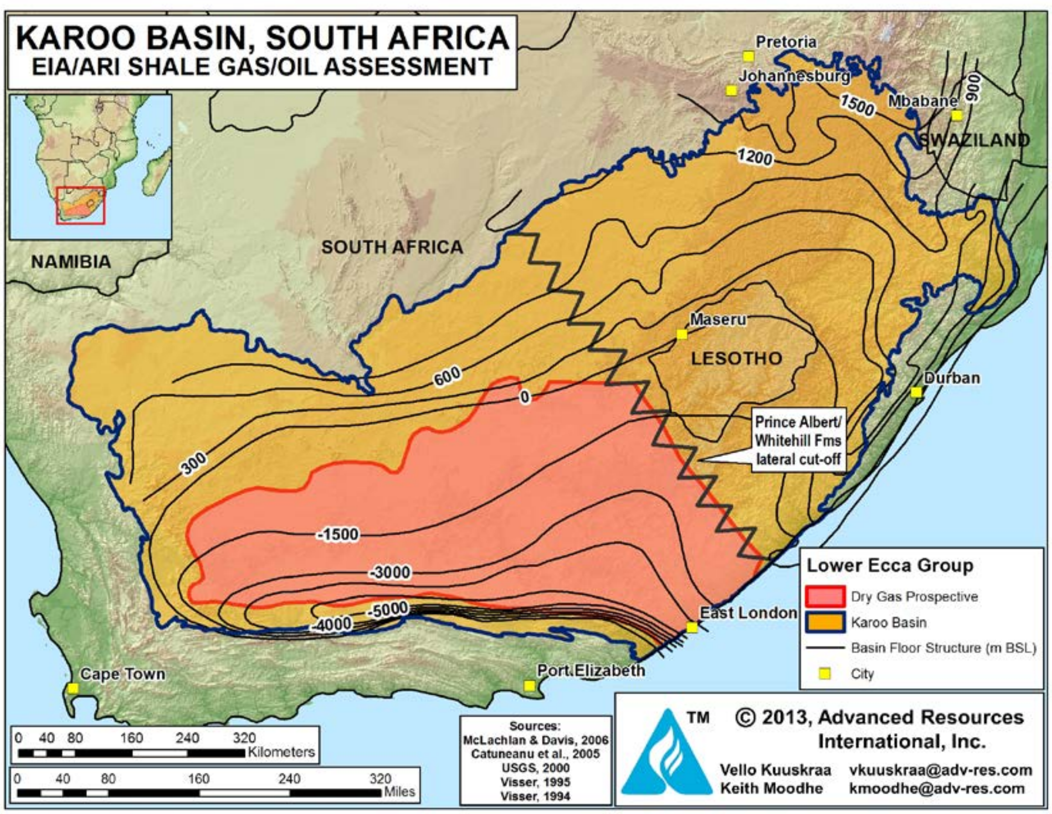
The prospective area for the Lower Ecca Group shales is estimated at 60,180 mi^2, Figure XIX-5. The boundaries of the prospective area are defined by the outcrop of the Upper Ecca Group on the east, south and west/northwest and the pinch-out of the Lower Ecca Group shales on the northeast, Figure XIX-1. The dry gas window is south of the approximately 29^o latitude line. Given the thermal maturity information and the depositional limits of the Lower Ecca shales, the prospective area of the Lower Ecca shales is primarily in the dry gas window.

Figure XIX-4. Igneous Intrusions in the Karoo Basin, South Africa



Source: Svensen, H. et al., 2007.

Figure XIX-5. Lower Ecca Group Structure Map, Karoo Basin, South Africa



Source: ARI, 2013.

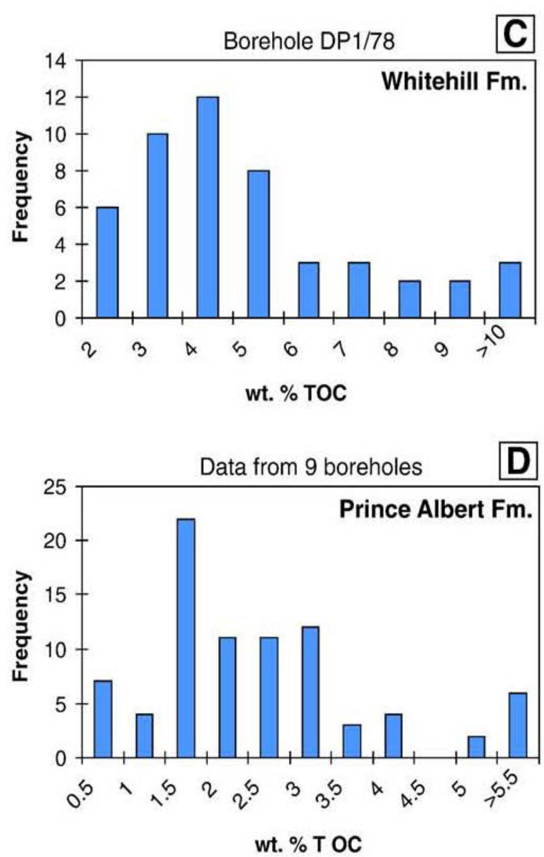
1.2 Reservoir Properties (Prospective Area)

Lower Ecca Shales. The Lower Ecca shales include the thick basal Prince Albert Formation, overlain by the thinner Whitehill and Collingham Formations. Each of these sedimentary units has been individually assessed and is discussed below.

Prince Albert Shale. The Lower Permian Prince Albert Formation has a thick, thermally mature area for shale gas in the Karoo Basin. Depth to the Prince Albert Shale ranges from 6,000 to over 10,000 ft, averaging about 8,500 ft in the deeper prospective area in the south. The Prince Albert Shale has a gross thickness that ranges from 200 to 800 ft, averaging 400 ft, with a net organic-rich thickness of about 120 ft.

The total organic content (TOC) of the Prince Albert Shale within its organic-rich net pay interval ranges from 1.5 to 5.5%, averaging 2.5%, Figure XIX-6.[8] Local TOC values of up to 12% have been recorded.[9] However, in areas near igneous intrusions much of the organic content may have been lost or converted to graphite.

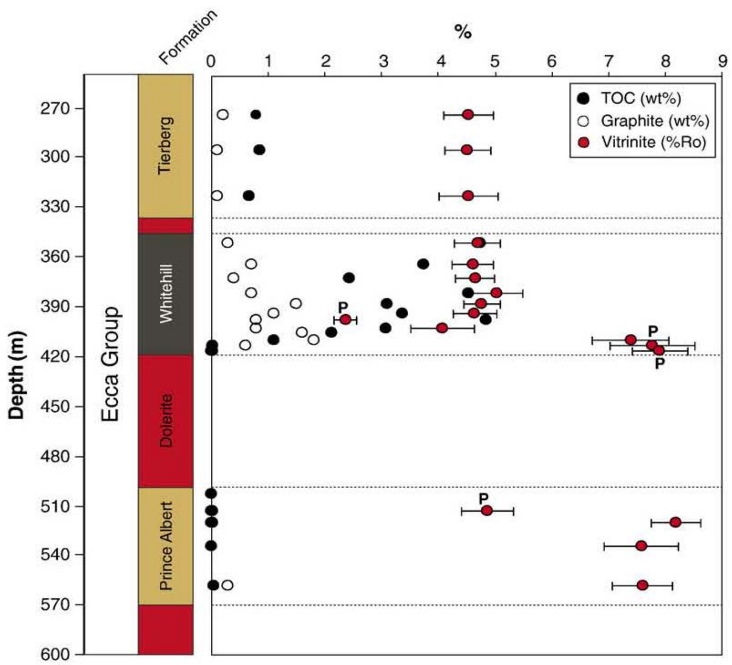
Figure XIX-6. Total Organic Content of Prince Albert and Whitehill Formations



Source: Svensen, H. et al., 2007.

Because of the presence of igneous intrusions, the thermal maturity of the Prince Albert Shale is high, estimated at 2% to 4% R_o, placing the shale well into the dry gas window. In areas near igneous intrusions, the formation is over-mature, with vitrinite reflectance (R_o) values reaching 8%, indicating that the organic content has been transformed into graphite and CO_2, Figure XIX-7. The Prince Albert Shale was deposited as a deep marine sediment and is inferred to have mineralogy favorable for shale formation stimulation.

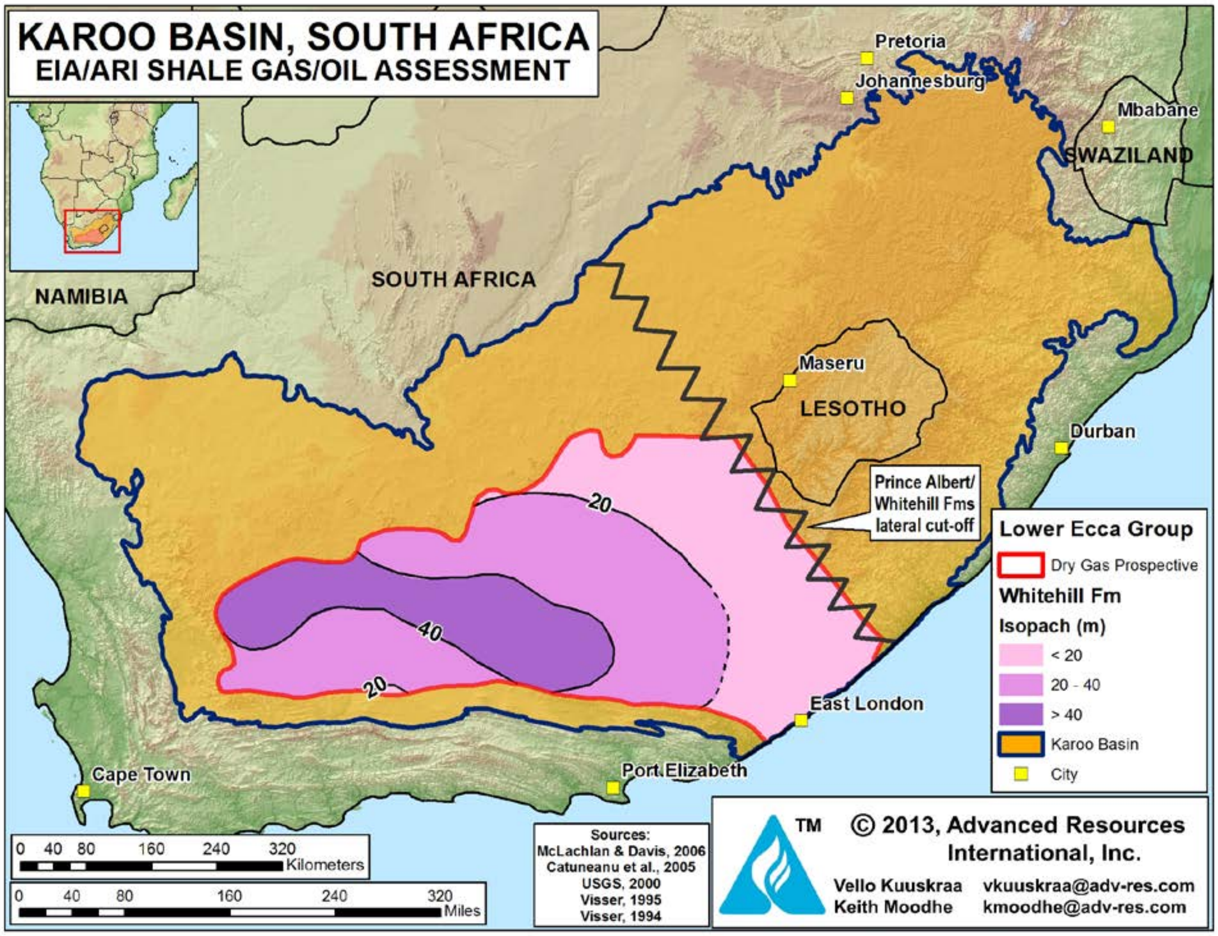
Figure XIX-7. Carbon Loss in Lower Ecca Group Metamorphic Shale



Based on limited well data, primarily from the Cranemere CR 1/68 well completed in the Upper Ecca interval, the Prince Albert Shale appears to be overpressured and has a high thermal gradient.

Whitehill Shale. The organic-rich Lower Permian Whitehill Formation contains one of the main shale gas targets in the Karoo Basin of South Africa. The depth to the Whitehill Shale ranges from 5,500 to 10,000 ft, averaging 8,000 ft in the prospective area. The Whitehill Shale has an estimated gross organic thickness of 100 to 300 ft,[10] with an average net thickness of 100 ft within the prospective area, as shown by the isopach map on Figure XIX-8.[11]

Figure XIX-8. Isopach Map of the Whitehill Formation



Source: ARI, 2013.

The total organic content (TOC) for the Whitehill Shale in the prospective area ranges from 3% to 14%, averaging 6%. Local areas have TOC contents up to 15%.[4] In areas near igneous intrusions, portions of the organic content may have been converted to graphite. The main minerals in the Whitehill Formation are quartz, pyrite, calcite and chlorite, making the shale favorable for hydraulic stimulation. The Whitehill Shale is assumed to be overpressured. The thermal maturity (R_o) of the Whitehill Shale in the prospective area ranges from 2% to 4%, placing the shale into the dry gas window.

The hydrogen and oxygen indexes of the Whitehill Formation indicate a mixture of Type I and Type II kerogen.[9] The Whitehill Shales was deposited in deep marine, anoxic setting and contains minor sandy interbeds from distal turbidites and storm deposits.[12,13]

Collingham Shale. The Lower Permian Collingham Formation (often grouped with the Whitehill Formation) contains the third shale formation addressed by this resource study. The Collingham Formation has an upward transition from deep-water submarine to shallow-water deltaic deposits.[9] The depth to the Collingham Shale averages 7,800 ft within the prospective area. Except for total organic content, the shale has reservoir properties similar to the Whitehill Shale. It has an estimated gross organic thickness of 200 ft, a net thickness of 80 ft, and TOC of 2% to 8%, averaging 4%. Thermal maturity is high, estimated at 3% R_o, influenced by igneous intrusions. The shale is assumed to be overpressured based on data from the Upper Ecca Group.

Upper Ecca Shales. The Upper Ecca Formation extends over a particularly thick, 1,500 m (~5,000 ft) vertical interval in the central and northern Karoo Basin. The Upper Ecca contains two shale sequences of interest - - the Waterford and the Fort Brown. The Fort Brown Formation accounts for the great bulk of the vertical interval of the Upper Ecca. These shales are interpreted by some investigators to have been deposited in a shallow marine environment,[2] although others categorize them as lacustrine.[14]

The organic content and thermal maturity of the Upper Ecca shales are considerably less than for the Lower Ecca shales. The total organic content (TOC) is reported to range from about 1% to 2%. With a thermal maturity ranging from 0.9% to 1.1% R_o, the Upper Ecca shales area is in the oil to wet gas window.[15]

In the materials below, we provide a qualitative description for the Upper Ecca shales. However, because their average TOC is below the 2% criterion set for the study, these shales have been excluded from our quantitative assessment.

The boundaries of the prospective area for the Upper Ecca shales are defined by the outcrop of the Upper Ecca on the east, south and west and the shallowing of the Lower Ecca shales on the northeast. The shale oil window is north of the approximately 29^o latitude line. A significant basalt intrusion area of about 10,000 mi^2 in the center of the prospective area has been excluded. Major portions of the prospective area have igneous intrusions that have locally destroyed portions of the organics, creating significant exploration risk.

Fort Brown Shale. The Fort Brown Shale, as described in the Cranemere CR 1/68 well, is a dark gray to black shale with occasional siltstone stringers. In this well, the Fort Brown Shale exists over a gross interval of nearly 5,000 ft (1,500 m) from 7,012-11,997 ft. Sunset

Energy, the current permit holder in the area surrounding the Cranemere CR 1/68 well, reports that 24-hour DST testing in one interval of the Fort Brown shale, from 8,154-8,312 ft, had a flow rate of 1.84 MMcfd. The well is reported to have blown out at a depth of about 8,300 ft (2,500 m), requiring 10.5 pound per gallon mud to bring the well under control.

The prospective area for the Upper Ecca Fort Brown Shale is estimated at 31,700 mi^2. The Fort Brown Shale in the prospective area has an average depth of 6,000 ft and ranges from 3,000 to 9,000 ft. The shale has an estimated 600 ft of net organic rich thickness, based on using a net to gross ratio of 20% and an average gross thickness of 3,000 ft. The shale has a total organic content (TOC) that ranges from 1 to 2% and an estimated average thermal maturity of 1.1% R_o (based on limited data).

Waterford Shale. The prospective area for the Upper Ecca Waterford Shale is estimated at 20,800 mi^2. The Waterford Shale in the prospective area has an average depth of 4,500 ft, ranging from 3,000 to 6,000 ft. The shale has an estimated 100 ft of net organic rich thickness within an average gross thickness of 500 ft. Total organic content ranges from 1 to 2%, with average thermal maturity, based on very limited data, of 0.9% R_o.

1.3 Resource Assessment

Prince Albert Shale. Within its 60,180-mi^2 dry gas prospective area, the Prince Albert Shale has a resource concentration of about 43 Bcf/mi^2. Given limited exploration data, the risked shale gas in-place is estimated at 385 Tcf. Based on favorable TOC and reservoir mineralogy, balanced by complex geology and volcanic intrusions in the prospective area, ARI estimates a risked, technically recoverable shale gas resource of 77 Tcf for the Prince Albert Shale in the Karoo Basin.

Whitehill Shale. Within its 60,180-mi^2 dry gas prospective area, the Whitehill Shale has a resource concentration of about 59 Bcf/mi^2. While somewhat more defined than the Prince Albert Shale, the exploration risk for the Whitehill Shale is still substantial, leading to a risked shale gas in-place of 845 Tcf. Based on favorable reservoir mineralogy but complex geology, ARI estimates a risked, technically recoverable shale gas resource of 211 Tcf for the Whitehill Shale in the Karoo Basin.

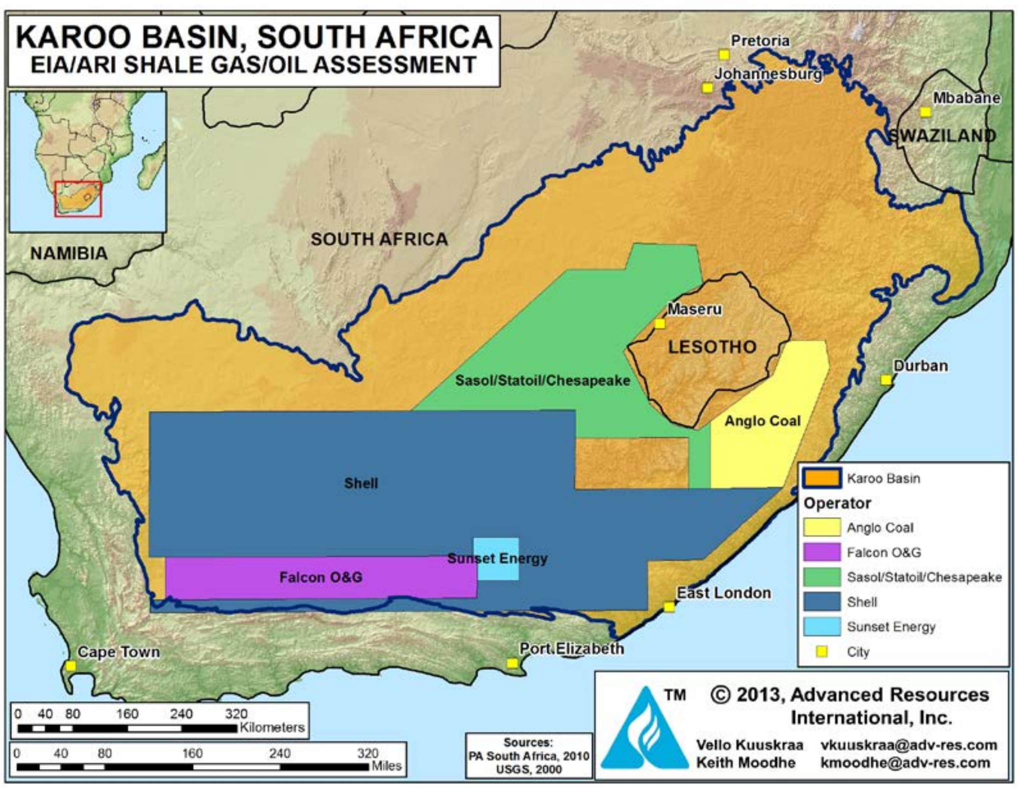
Collingham Shale. With a prospective area of 60,180 mi^2 and with a resource concentration of 36 Bcf/mi^2, the risked gas in-place for the Collingham Shale is estimated at 328 Tcf, with a risked, technically recoverable shale gas resource of 82 Tcf.

Considerable uncertainty surrounds the characterization and assessment of the shale oil resources of South Africa, particularly for the net organic-rich thickness and the vertical and areal distribution of thermal maturity. Shale exploration is just starting in the Karoo Basin and few data points exist, particularly for the Upper Ecca group of formations.

1.4 Recent Activity

Falcon Oil & Gas Ltd., an early entrant into the shale gas play of South Africa, obtained an 11,600-mi^2 TCP along the southern edge of the Karoo Basin. Shell obtained a larger 71,400-mi^2 TCP surrounding the Falcon area. Sunset Energy holds a 1,780-mi^2 TCP to the west of Falcon. The Sasol/Chesapeake/Statoil JV TCP area of 34,000 mi^2 and the Anglo Coal TCP application area of 19,300 mi^2 are to the north and east of Shell's TPC, Figure XIX-9. [16]

Figure XIX-9. Map Showing Operator Permits in the Karoo Basin, South Africa



Source: ARI, 2013.

Recently, Chevron announced that it would partner with Falcon Oil & Gas to pursue the shale resources of the Karoo Basin, starting with seismic studies.[17]

Five older (pre-1970) wells have penetrated the Ecca Shale interval. Each of the wells had gas shows, while one of the wells - - the Cranemere CR 1/68 well - - flowed 1.84 MMcfd from a test zone at 8,154 to 8,312 ft. The gas production, considered to be from fractured shale, depleted relatively rapidly during the 24-hour test. The CR 1/68 well was drilled to 15,282 ft into the underlying Table Mountain quartzite and had gas shows from six intervals, starting at 6,700 ft and ending at 14,650 ft, indicating that the shales in this area are gas saturated.

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