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Technically Recoverable Shale Oil and Shale Gas Resources:

Tunisia

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Executive Summary

Introduction

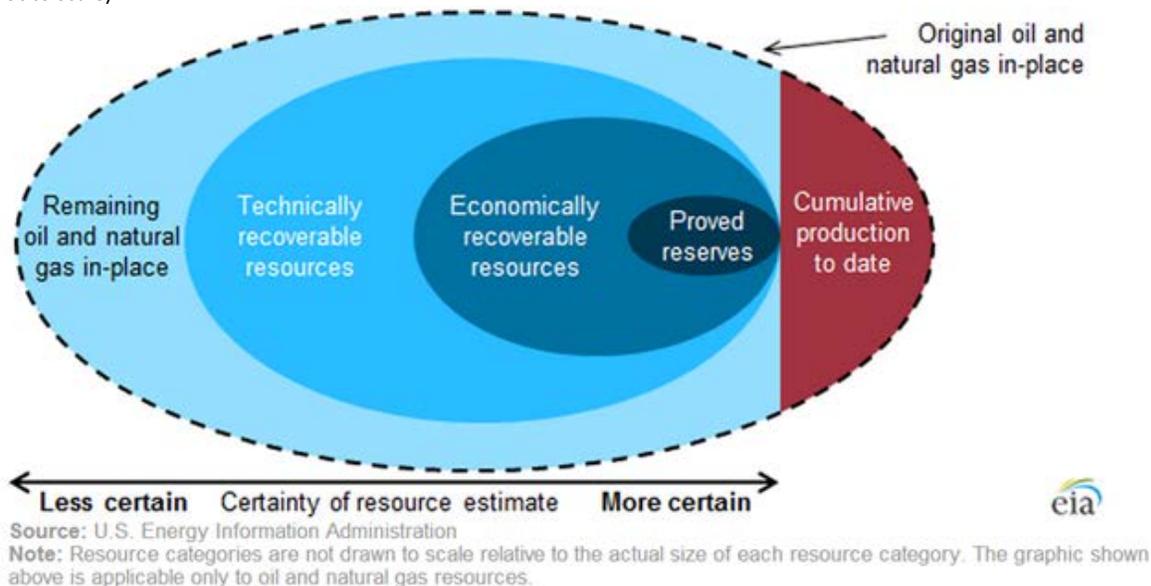
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

Resource categories

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

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

(not to scale)



Crude oil and natural gas resources are the estimated oil and natural gas volumes that might be produced at some time in the future. The volumes of oil and natural gas that ultimately will be produced cannot be known

ahead of time. Resource estimates change as extraction technologies improve, as markets evolve, and as oil and natural gas are produced. Consequently, the oil and gas industry, researchers, and government agencies spend considerable time and effort defining and quantifying oil and natural gas resources.

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

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

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

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

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

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

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

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

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

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

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

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

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

Methodology

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

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

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

1. Conduct a preliminary review of the basin and select the shale formations to be assessed.

2. Determine the areal extent of the shale formations within the basin and estimate its overall thickness, in addition to other parameters.
3. Determine the prospective area deemed likely to be suitable for development based on depth, rock quality, and application of expert judgment.
4. Estimate the natural gas in-place as a combination of *free gas*¹ and *adsorbed gas*² that is contained within the prospective area. Estimate the oil in-place based on pore space oil volumes.
5. Establish and apply a composite success factor made up of two parts. The first part is a formation success probability factor that takes into account the results from current shale oil and shale gas activity as an indicator of how much is known or unknown about the shale formation. The second part is a prospective area success factor that takes into account a set of factors (e.g., geologic complexity and lack of access) that could limit portions of the prospective area from development.
6. For shale oil, identify those U.S. shales that best match the geophysical characteristics of the foreign shale oil formation to estimate the oil in-place recovery factor.³ For shale gas, determine the recovery factor based on geologic complexity, pore size, formation pressure, and clay content, the latter of which determines a formation's ability to be hydraulically fractured. The gas phase of each formation includes dry natural gas, associated natural gas, or wet natural gas. Therefore, estimates of shale gas resources in this report implicitly include the light wet hydrocarbons that are typically coproduced with natural gas.
7. Technically recoverable resources⁴ represent the volumes of oil and natural gas that could be produced with current technology, regardless of oil and natural gas prices and production costs. Technically recoverable resources are determined by multiplying the risked in-place oil or natural gas by a recovery factor.

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

Key exclusions

In addition to the key distinction between technically recoverable resources and economically recoverable resources that has been already discussed at some length, there are a number of additional factors outside of the scope of this report that must be considered in using its findings as a basis for projections of future

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

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

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

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

production. In addition, several other exclusions were made for this supplement as in the previous report to simplify how the assessments were made and to keep the work to a level consistent with the available funding.

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

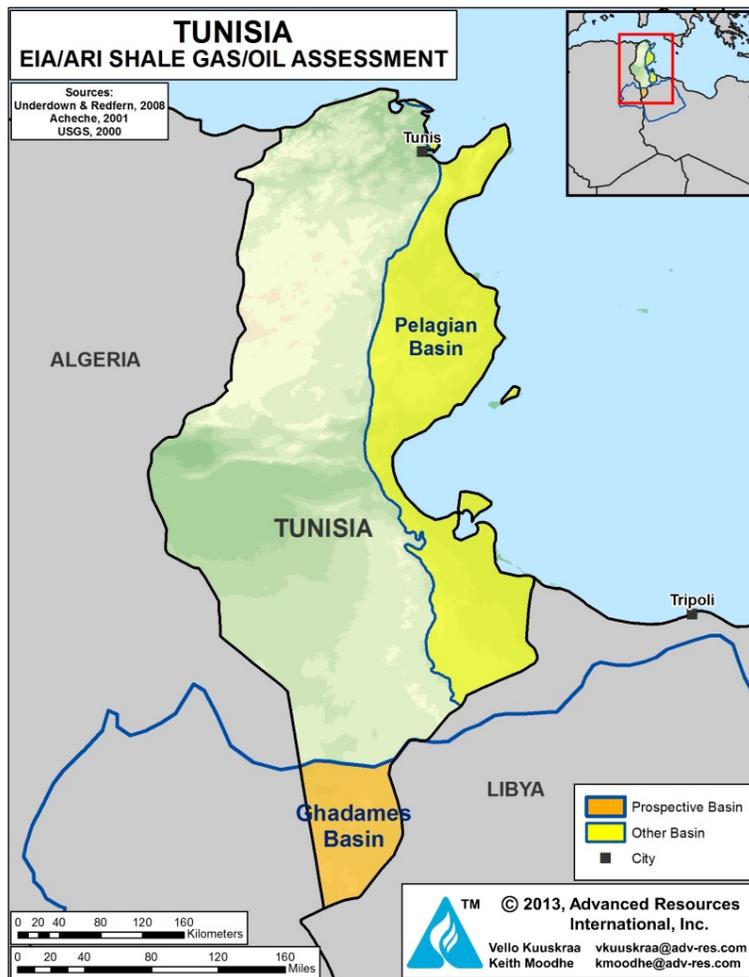
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

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.

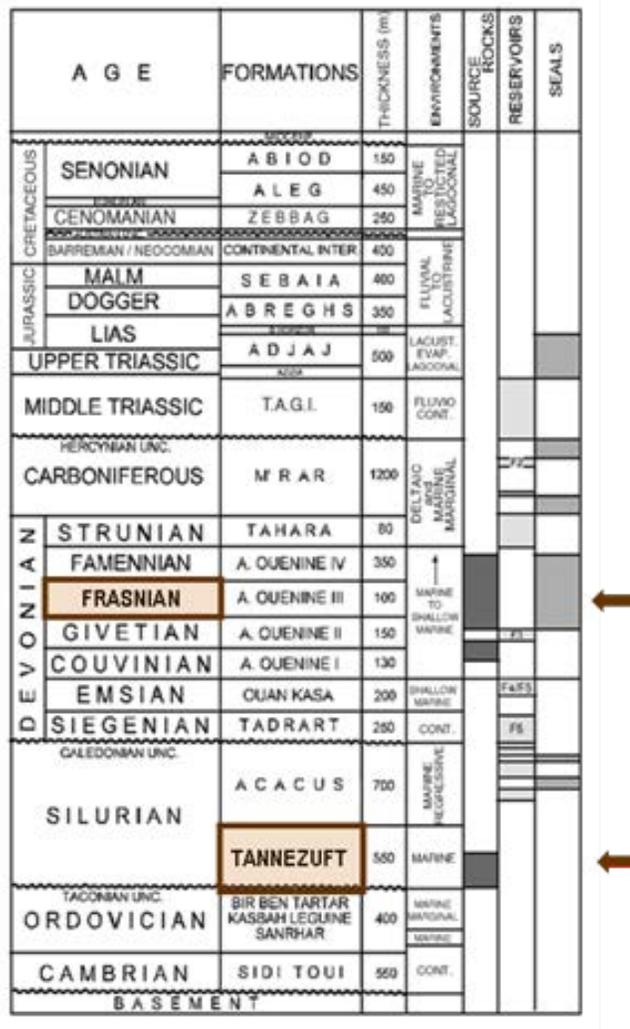
Basic Data	Basin/Gross Area		Ghadames (117,000 mi ²)		
	Shale Formation		Tannezuft	Frasnian	
	Geologic Age		Silurian	U. Devonian	
	Depositional Environment		Marine	Marine	
Physical Extent	Prospective Area (mi ²)		410	1,210	850
	Thickness (ft)	Organically Rich	115	197	197
		Net	104	177	177
	Depth (ft)	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

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.

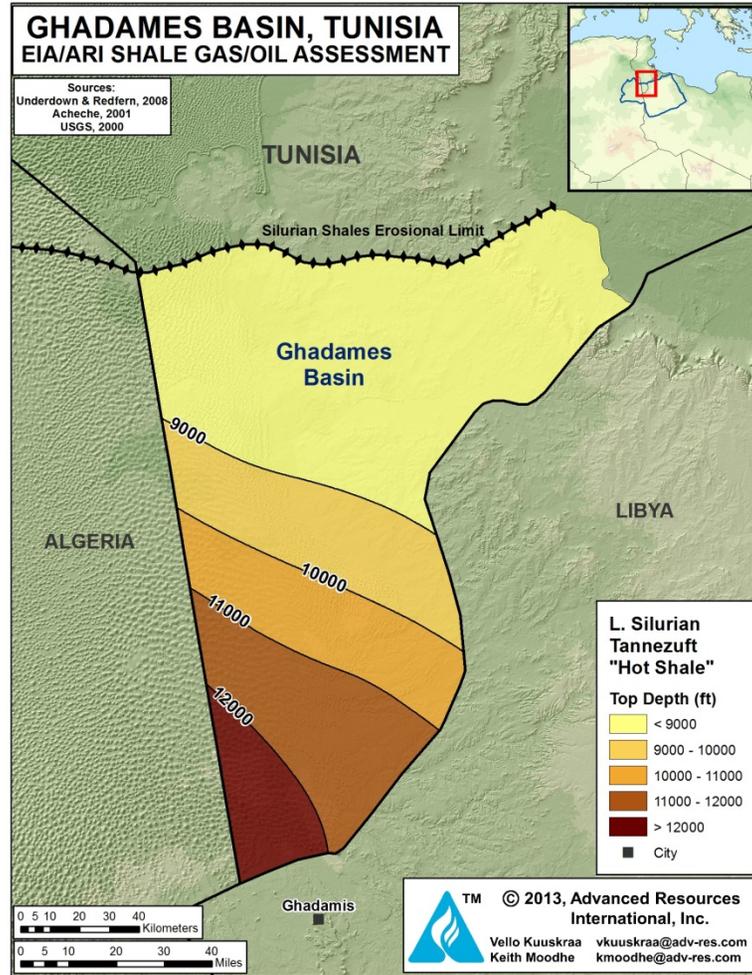
The Ghadames Basin and its two significant shale formations are located in the southern portion of Tunisia. Figures XVI-3 and XVI-4 provide the Ghadames Basin's shale outline and depth contours for the Silurian Tannezuft "Hot Shale"¹ and the Upper Devonian Frasnian Shale.

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-mi² 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 mi² 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 mi² for the Tannezuft "Hot Shale", with R_o greater than 1.3%, is in the dry gas window, Figure XVI-5.

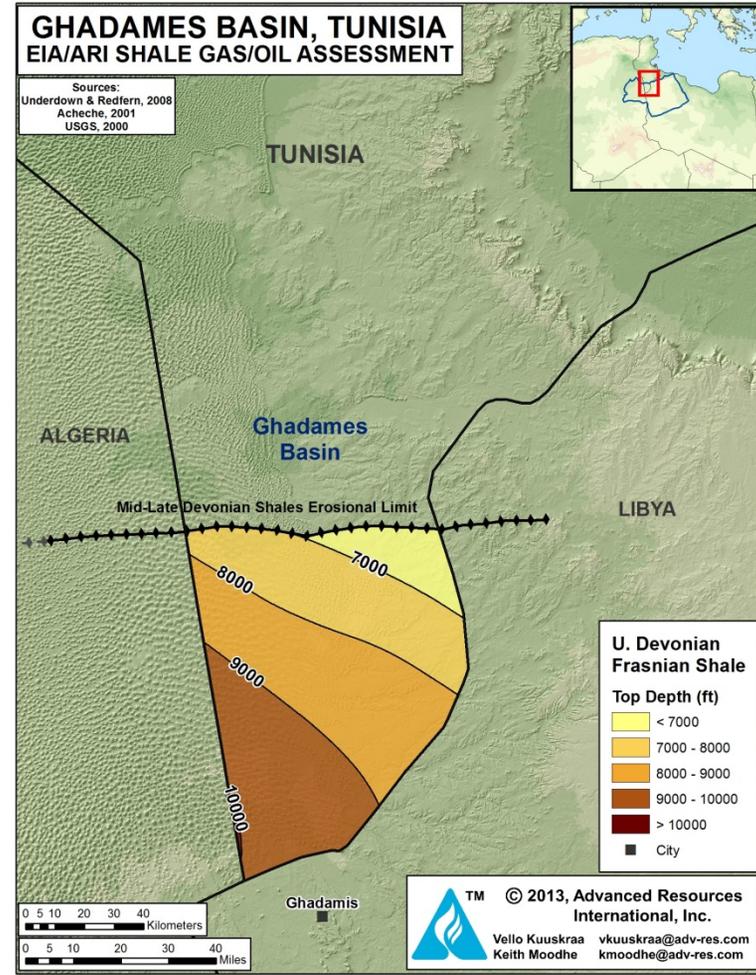
Deposited above the Tannezuft "Hot Shale" is the thermally less mature Frasnian Shale. We have mapped a 2,140-mi² prospective area for the Frasnian Shale in Tunisia's portion of the Ghadames Basin. The northern boundary of the Frasnian Shale prospective area is the minimum oil maturity criterion of 0.7% 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-mi² 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-mi² 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-mi² 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.

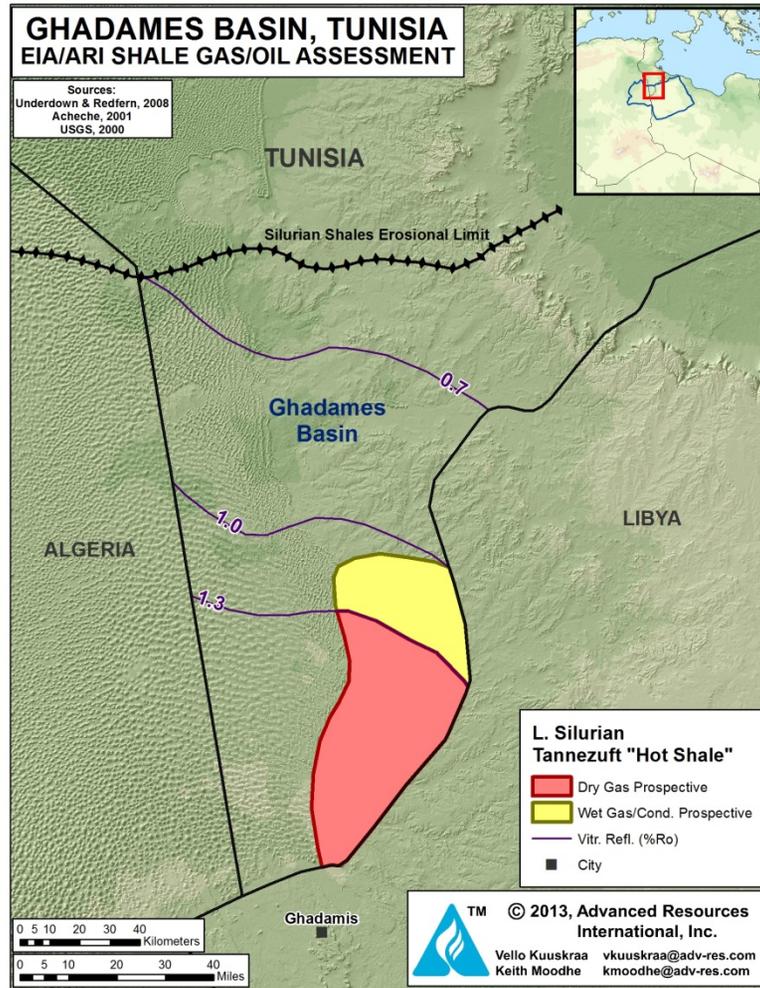
1.2 Reservoir Properties (Prospective Area)

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 Llandoveryan “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.

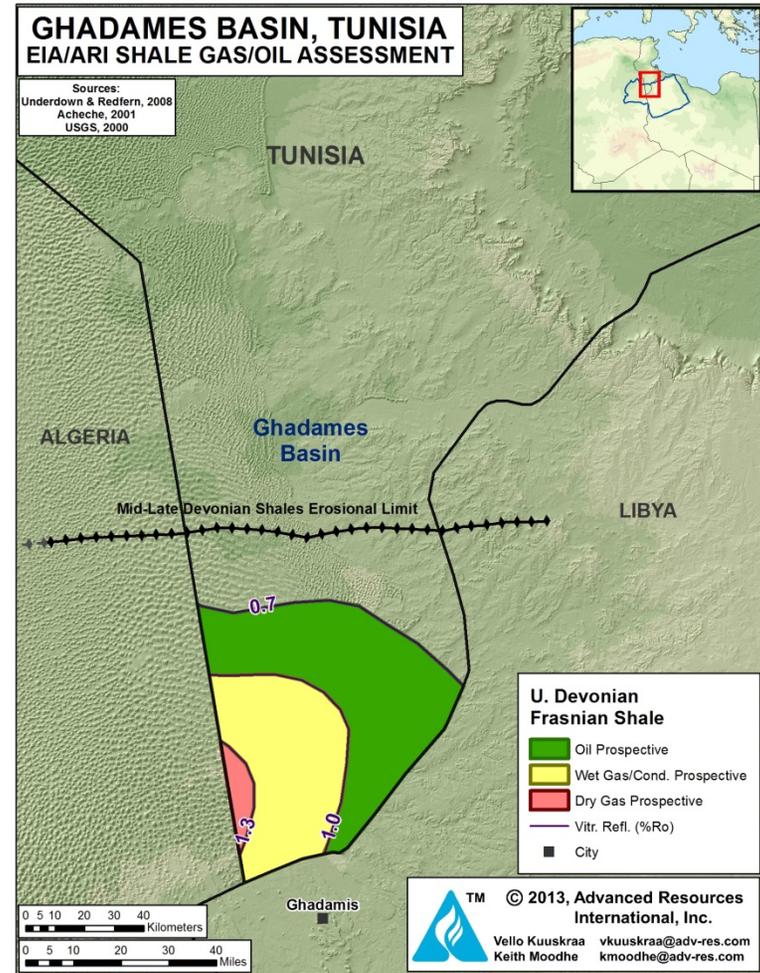
Upper Devonian Frasnian Shale. The depth of the overlying Upper Devonian Frasnian Shale in the prospective area ranges from 8,000 ft to 11,000 ft, averaging 8,500 ft in the oil-prone area, 9,500 ft in the wet gas/condensate area, and 10,500 ft in the dry gas area, Figure XVI-3. The Frasnian Shale has 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-mi² wet gas and condensate prospective area, has resource concentrations of 43 Bcf/mi² of wet gas and 3.1 million barrels/mi² of condensate. Within its 940-mi² dry gas prospective area, the Tannezuft “Hot Shale” has a resource concentration of 54 Bcf/mi².

The risked resource in-place for the overall 1,350-mi² 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-mi² prospective area has resource concentrations of 31 million barrels/mi² of oil (plus associated gas) in the 1,210-mi² oil window, 7 million barrels/mi² of condensate and 80 Bcf/mi² of wet gas in the 850-mi² wet gas/condensate window, and 101 Bcf/mi² of dry gas in the 80-mi² dry gas window.

The risked resource in-place within the overall 2,140-mi² 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° 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° to 53° 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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