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U.S. Energy Information Administration

Technically Recoverable Shale Oil and Shale Gas Resources:

Egypt

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Executive Summary

Introduction

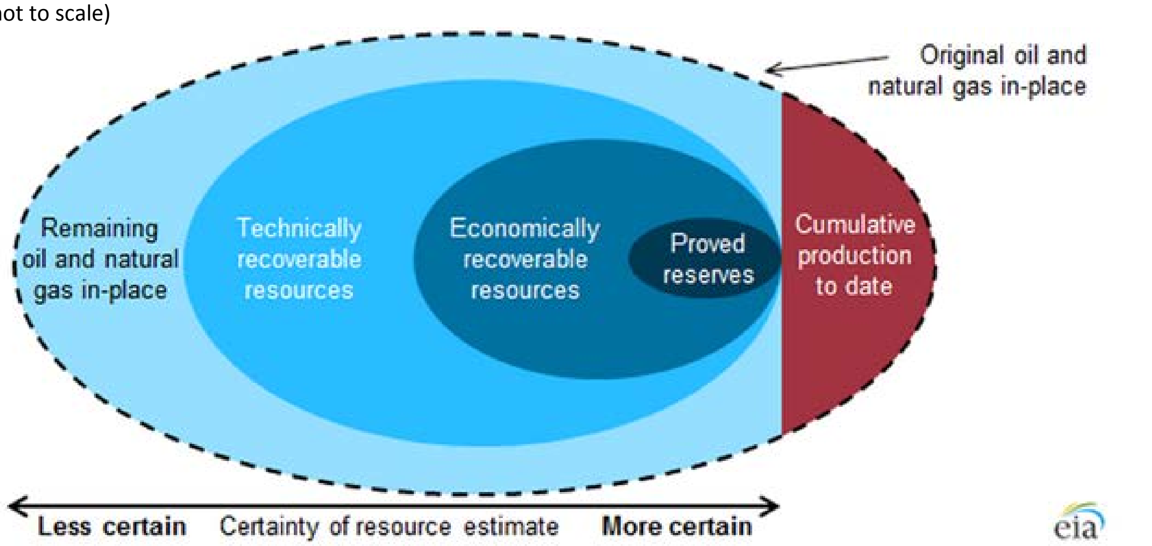
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically 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)



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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Methodology

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

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

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

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

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

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

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:

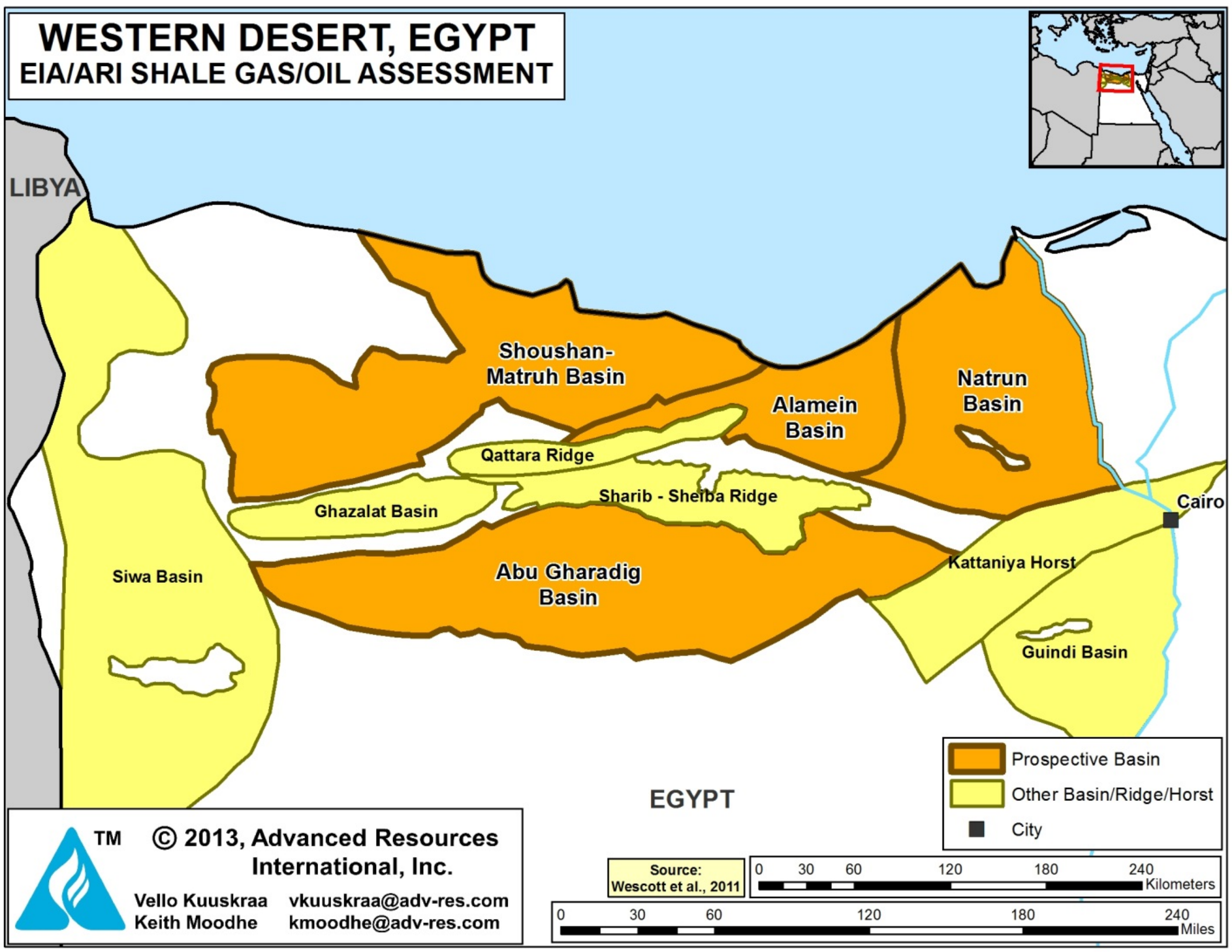
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas 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.

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

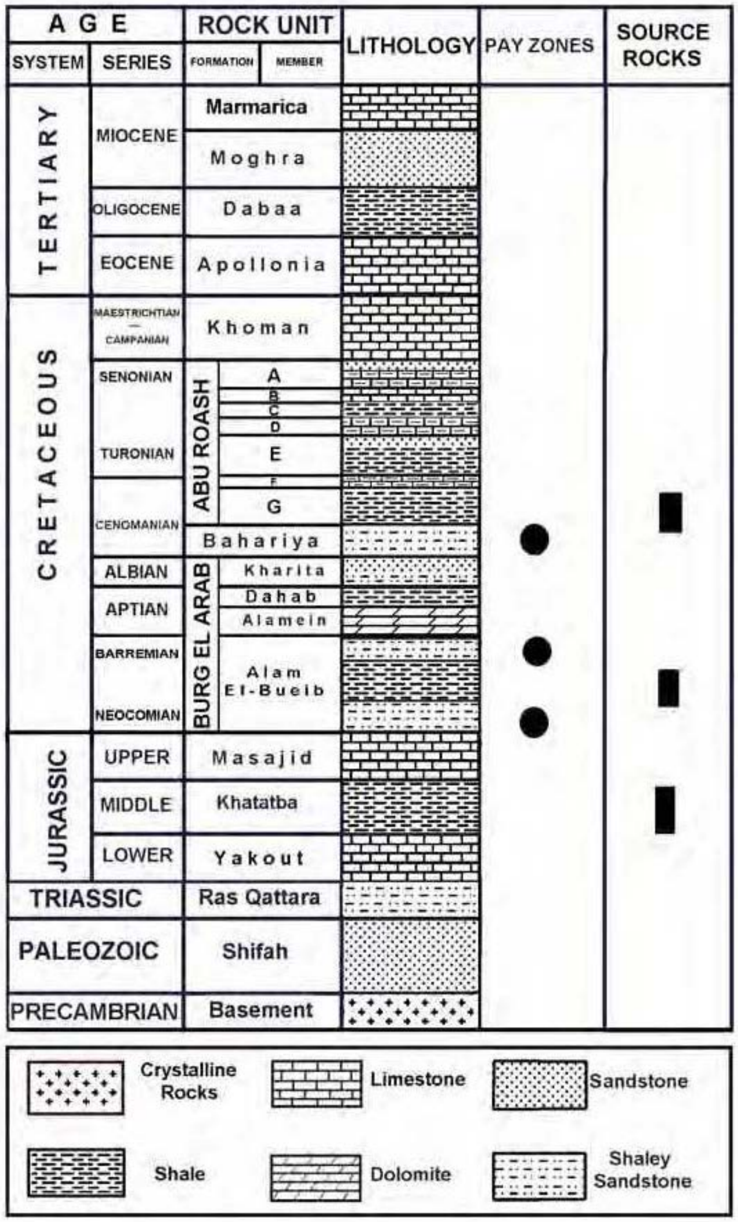
INTRODUCTION

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.

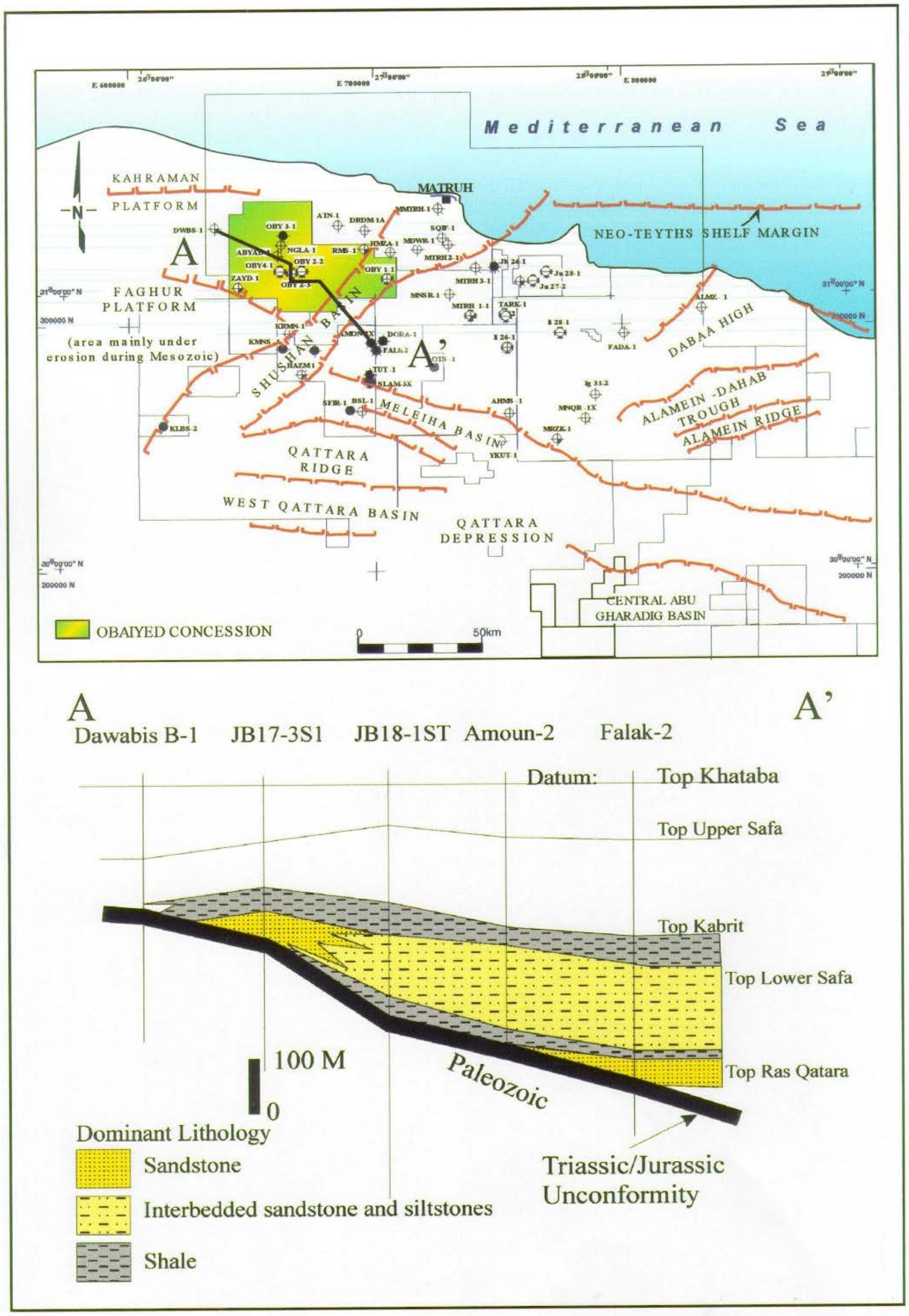
The focus of our shale resource study is the Khatatba Shale within the Middle Jurassic Khatatba Formation, also called the Kabrit Shale and the Safa Shale, Figure XVIII-3.[4]

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.

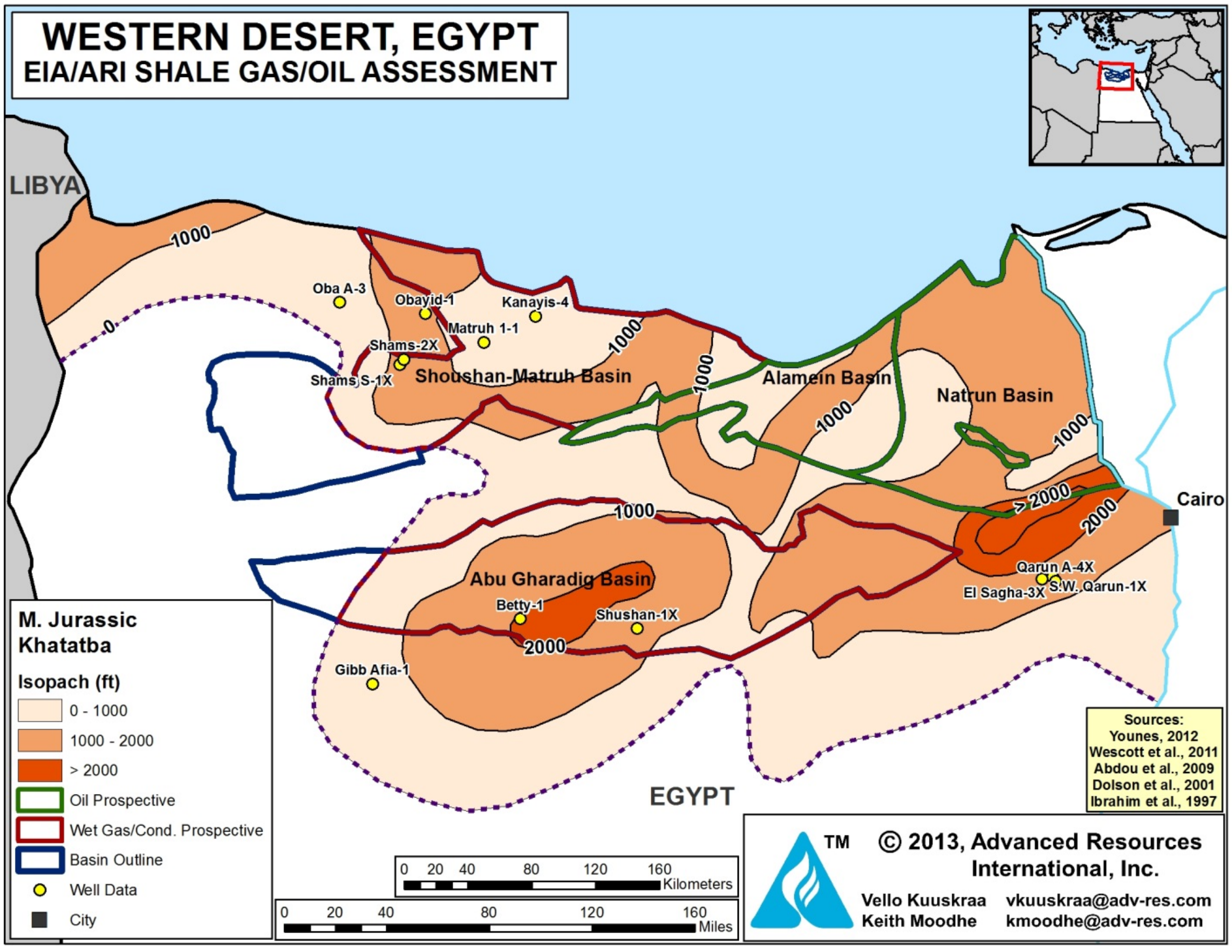
Silurian. A thick sequence of Silurian siltstone, estimated at about 200 to 300 m in the Basur-1 and Kohka-1 wells, exists in the northwestern portion of the Western Desert.[5] These sandstones and siltstones thin to the south and east as shown by the Foram-1 and Sheiba-1 wells.[6] The sandstone and 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]

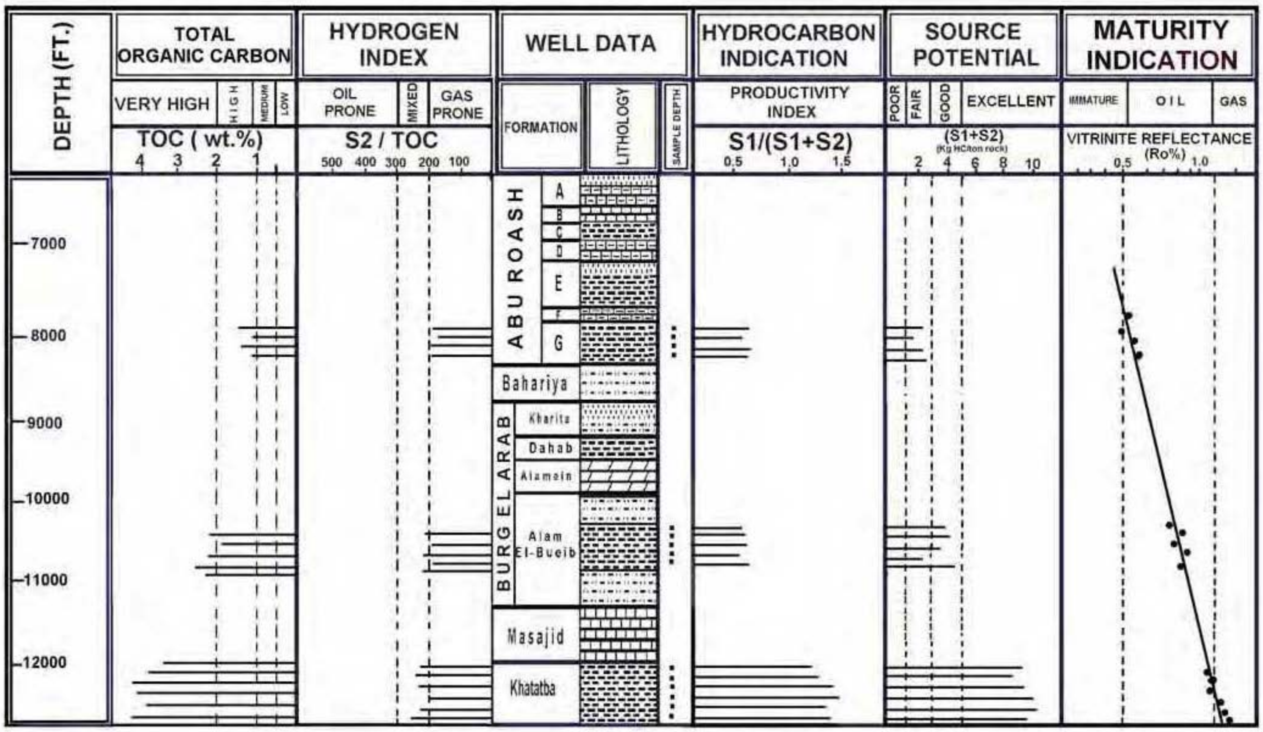
Figure XVIII-4. Middle Jurassic Khatatba Formation Gross Isopach



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.

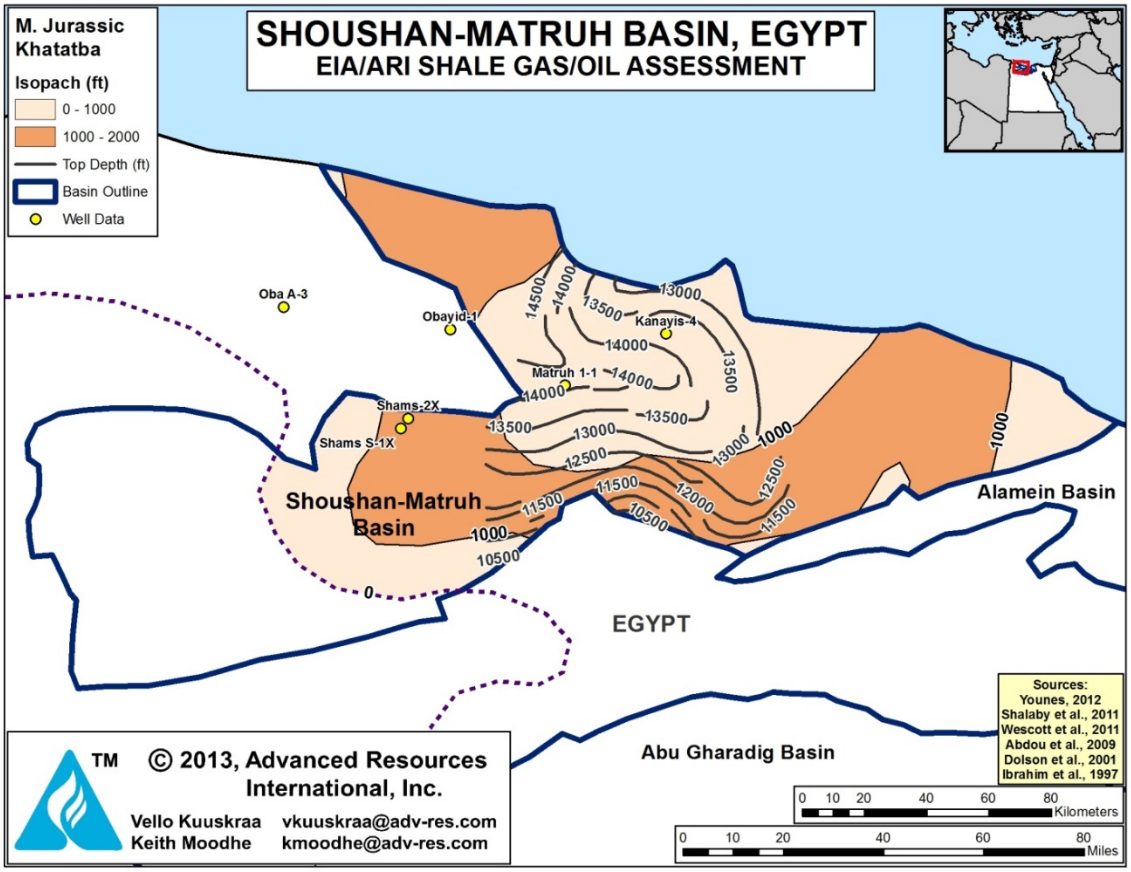
Reservoir Properties (Prospective Area). Within the 4,860-mi^2 prospective area, the depth of the Khatatba Shale in the Natrun Basin ranges from 13,000 to 15,000 ft, averaging 14,000 ft. The gross interval of the Khatatba Formation ranges from near 0 to over 2,000 ft, averaging about 1,200 ft thick. 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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