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Technically Recoverable Shale Oil and Shale Gas Resources:

Northern South America

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Executive Summary

Introduction

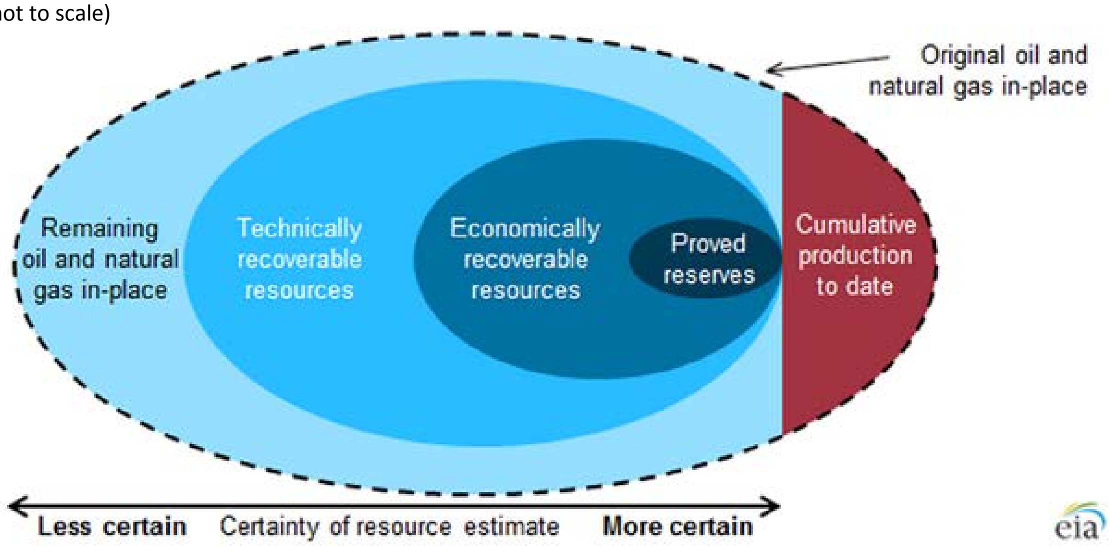
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

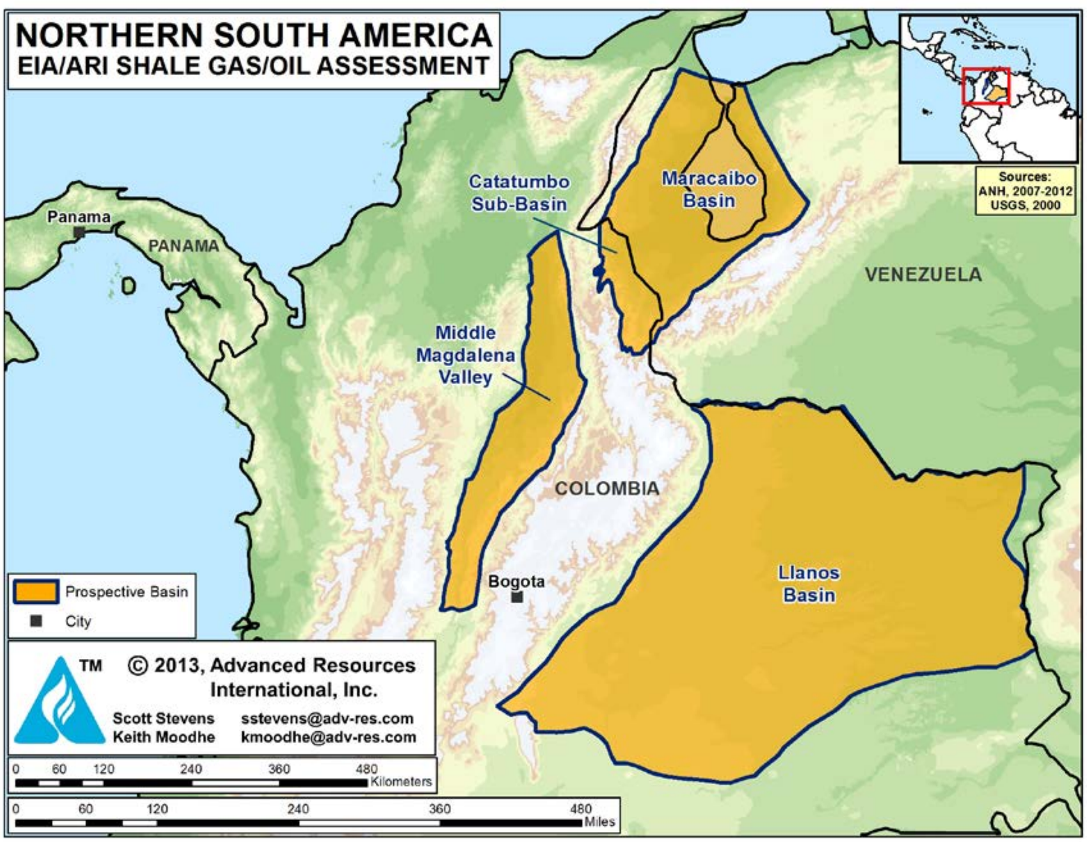
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

IV. NORTHERN SOUTH AMERICA

SUMMARY

Northern South America has prospective shale gas and shale oil potential within marine-deposited Cretaceous shale formations in three main basins: the Middle Magdalena Valley and Llanos basins of Colombia, and the Maracaibo/Catatumbo basins of Venezuela and Colombia, **Figure IV-1**. The organic-rich Cretaceous shales (La Luna, Capacho, and Gacheta) sourced much of the conventional gas and oil produced in Colombia and western Venezuela, and are similar in age to the Eagle Ford and Niobrara shale plays in the USA. Ecopetrol, ConocoPhillips, ExxonMobil, Shell, and others have initiated shale exploration in Colombia. Colombia's petroleum fiscal regime is considered attractive to foreign investment.

Figure IV-1: Prospective Shale Basins of Northern South America



Source: ARI 2013

For the current EIA/ARI assessment, the Maracaibo-Catatumbo Basin was re-evaluated while new shale resource assessments were undertaken on the Middle Magdalena Valley and Llanos basins. Technically recoverable resources (TRR) of shale gas and shale oil in northern South America are estimated at approximately 222 Tcf and 20.2 billion bbl, **Tables IV-1 and IV-2**. Colombia accounts for 6.8 billion barrels and 55 Tcf of risked TRR, while western Venezuela has 13.4 billion barrels and 167 Tcf. Eastern Venezuela may have additional potential but was not assessed due to lack of data.

Colombia's first publicly disclosed shale well logged 230 ft of over-pressured La Luna shale with average 14% porosity. More typically, the black shales within the La Luna and Capacho formations total about 500 ft thick, 10,000 ft deep, calcareous, and average 2-5% TOC. Thermal maturity comprises oil, wet-gas, and dry-gas windows (R_o 0.7-1.5%). Shale formations in the Llanos and Maracaibo/Catatumbo basins have not yet been tested but also have good shale oil and gas potential.

INTRODUCTION

As first highlighted in EIA/ARI's 2011 assessment, Colombia and Venezuela both have excellent potential for shale oil and gas.. In particular, Colombia's shale potential appears considerably brighter today based on the results of initial shale drilling as well as the entry of major oil companies (ConocoPhillips, ExxonMobil, and Shell) as well as several smaller companies.

Colombia's Agencia Nacional de Hidrocarburos (ANH) regulates oil and gas exploration and development. The country's model contract for unconventional gas includes 8-year exploration and 24-year production terms. Preferential terms are in place for shale gas investment, including a 40% reduction in royalties and higher oil prices. In 2011 the National University of Colombia conducted a shale gas resource evaluation for ANH, estimating a total 33 Tcf of potential in the Eastern Cordillera, Eastern Llanos and Caguan-Putumayo regions. The study and methodology have not been disclosed; apparently shale oil resources were not assessed. ANH conducted Colombia's first auction of shale gas blocks in 2012.

Table IV-1: Northern South America Shale Gas Reservoir Properties and Resources.

			Middle Magdalena Valley (13,000 mi²)		Llanos (84,000 mi²)	Maracaibo/Catatumbo (23,000 mi²)		
Basic Data	Basin/Gross Area		Middle Magdalena Valley (13,000 mi²)		Llanos (84,000 mi²)	Maracaibo/Catatumbo (23,000 mi²)		
	Shale Formation		La Luna/Tablazo		Gacheta	La Luna/Capacho		
	Geologic Age		U. Cretaceous		U. Cretaceous	U. Cretaceous		
	Depositional Environment		Marine		Marine	Marine		
Physical Extent	Prospective Area (mi²)		2,390	200	1,820	7,280	4,290	5,840
	Thickness (ft)	Organically Rich	1,000	1,000	600	1,000	1,000	1,000
		Net	300	300	210	500	500	500
	Depth (ft)	Interval	3,300 - 16,400	3,300 - 10,000	13,000 - 16,400	5,000 - 15,000	5,500 - 15,000	6,000 - 15,000
		Average	10,000	8,000	14,500	10,000	11,000	12,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Mod. Overpress.	Normal	Normal	Normal
	Average TOC (wt. %)		5.0%	5.0%	2.0%	5.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	0.85%	1.15%	1.60%
	Clay Content		Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Assoc. Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi²)		88.0	150.3	40.4	71.8	176.1	255.7
	Risked GIP (Tcf)		117.8	16.8	18.2	183.0	264.4	522.6
	Risked Recoverable (Tcf)		14.1	4.2	1.8	18.3	52.9	130.7

Table IV-2: Northern South America Shale Oil Reservoir Properties and Resources.

Basic Data	Basin/Gross Area		Middle Magdalena Valley (13,000 mi²)		Llanos (84,000 mi²)	Maracaibo/Catatumbo (23,000 mi²)	
	Shale Formation		La Luna/Tablazo		Gacheta	La Luna/Capacho	
	Geologic Age		U. Cretaceous		U. Cretaceous	U. Cretaceous	
	Depositional Environment		Marine		Marine	Marine	
Physical Extent	Prospective Area (mi²)		2,390	200	1,820	7,280	4,290
	Thickness (ft)	Organically Rich	1,000	1,000	600	1,000	1,000
		Net	300	300	210	500	500
	Depth (ft)	Interval	3,300 - 16,400	3,300 - 10,000	13,000 - 16,400	5,000 - 15,000	5,500 - 15,000
		Average	10,000	8,000	14,500	10,000	11,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Mod. Overpress.	Normal	Normal
	Average TOC (wt. %)		5.0%	5.0%	2.0%	5.0%	5.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	0.85%	1.15%
	Clay Content		Low	Low	Low	Low	Low
Resource	Oil Phase		Oil	Condensate	Oil	Oil	Condensate
	OIP Concentration (MMbbl/mi²)		57.0	26.1	28.0	92.3	41.0
	Risked OIP (B bbl)		76.3	2.9	12.6	235.1	61.6
	Risked Recoverable (B bbl)		4.58	0.18	0.63	11.75	3.08

Advanced Resources International, Inc.

Venezuela's government and oil companies have not disclosed shale oil or shale gas exploration activities, although the potential in western Venezuela appears to be large and of high quality. Overall, three main basins are present in northern South America that contain prospective marine-deposited shales and were assessed in this report, Figure IV-2. These basins include:

- **Middle Magdalena Valley Basin (Colombia):** The focus of shale exploration leasing and drilling activity in the region thus far, the MMVB near Bogota also is Colombia's main conventional onshore production area. It contains thick deposits of the organic-rich Cretaceous La Luna Formation, mostly in the oil to wet gas windows.
- **Llanos Basin (Colombia):** This large basin in eastern Colombia has prospective Gacheta Formation source rock shales of Cretaceous age that are equivalent to the La Luna Fm. TOC and R_o generally appear low, but the western foothills region may be richer and more thermally mature.
- **Maracaibo/Catatumbo Basin (Venezuela and Colombia):** One of South America's richest petroleum basins, the Maracaibo (Venezuela) and Catatumbo (Colombia) basins have extensive oil and gas potential in thick, widespread Cretaceous La Luna Shale.
- A fourth basin, the **Putamayo Basin** in southern Colombia, also may contain shale potential but was not assessed due to lack of data. The Putamayo contains organic-rich Cretaceous shales in the Macarena Group.[1] While relatively shallow (3,000 ft) in this up-thrusted basin-edge location, the Macarena shales deepen towards the center of the basin where they may become less faulted. Hydraulic fracturing already is being used in the Putamayo Basin for conventional reservoirs.[2]

Figure IV-2: Stratigraphic Chart Showing Source Rocks And Conventional Reservoirs In Northern South America.

			COLOMBIA & VENEZUELA BASINS		
	BASIN		MID MAGDALENA VALLEY	MARACAIBO-CATATUMBO	LLANOS
ERA	PERIOD	EPOCH	F O R	M A T I	O N
CENOZOIC	QUATERNARY	Pleistocene	Alluvium	Alluvium	Necesidad
	TERTIARY	Pliocene	Mesa	Guayabo	Guayabo
		Miocene	Real	Leon	Leon
			Colorado	*Carbonera*	*Carbonera*
		Oligocene	*Mugrosa*		
			Esmeraldas		
		Eocene	*La Paz*	*Mirador*	*Mirador*
		Paleocene	Lisama	Los Cuervos	Los Cuervos
				Barco Catatumbo	Barco
MESOZOIC	CRETACEOUS	Upper	Umir	Mito Juan	Guadalupe
			La Luna	Colon	Gacheta
				La Luna	*Une*
			Simiti	Capacho	
		Lower		*Aguardiente*	
			Tablazo	*Apon*	
			Paja		
			Rosablanca	Rio Negro	
			Cumbre		
	JURASSIC		Arcabuco/ Giron	Giron	
	TRIASSIC				

Source Rock	*Conventional Reservoir*	Absent/Unknown

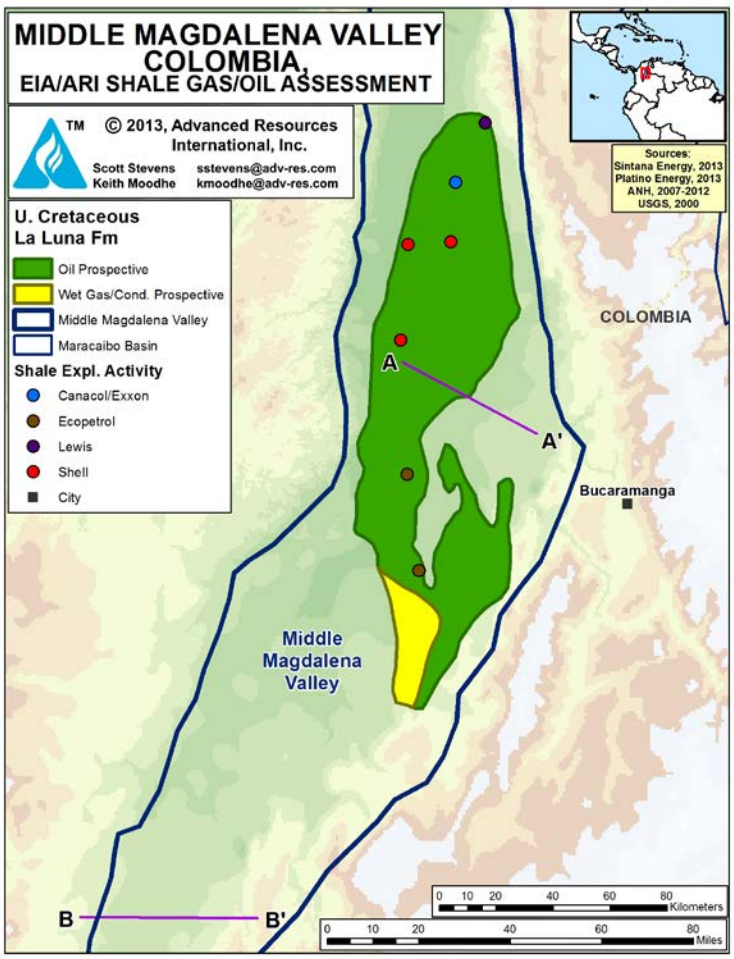
Source: ARI 2013

1. MIDDLE MAGDALENA VALLEY BASIN (COLOMBIA)

1.1 Introduction and Geologic Setting

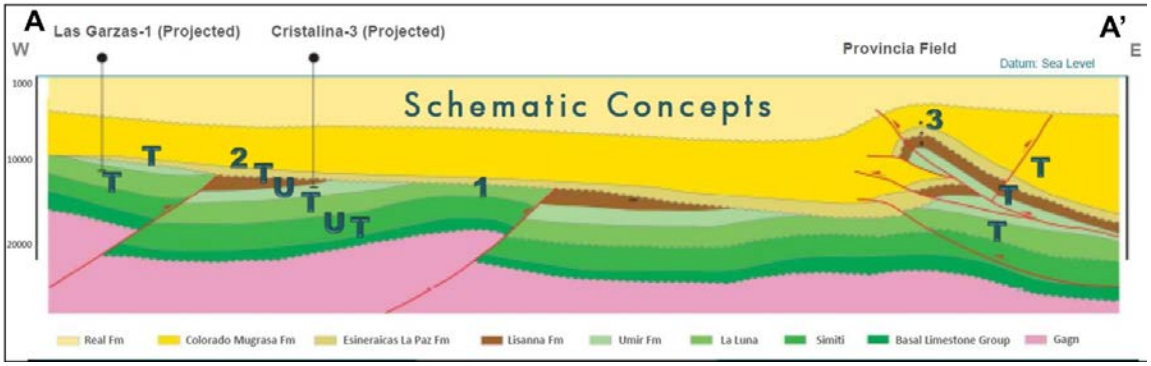
The 13,000-mi^2 Middle Magdalena Valley Basin (MMVB) is a north-south trending inter-montane basin in central Colombia, situated between the Eastern and Central cordilleras and located 150 miles north of Bogota, **Figure IV-3**. The MMVB is Colombia's most explored conventional oil and gas producing basin, with over 40 discovered oil fields that produce mainly from Tertiary sandstone reservoirs. Although within the Andes Mountains region, with its complex tectonics including numerous thrust and extensional faults, the interior of the MMVB has simpler structure with relatively flat surface topography, **Figure IV-4**.[3] The western side of the basin is structurally more complex and overthrusted, **Figure IV-5**.[4]

Figure IV-3: Middle Magdalena Valley Basin, Shale-Prospective Areas and Shale Exploration



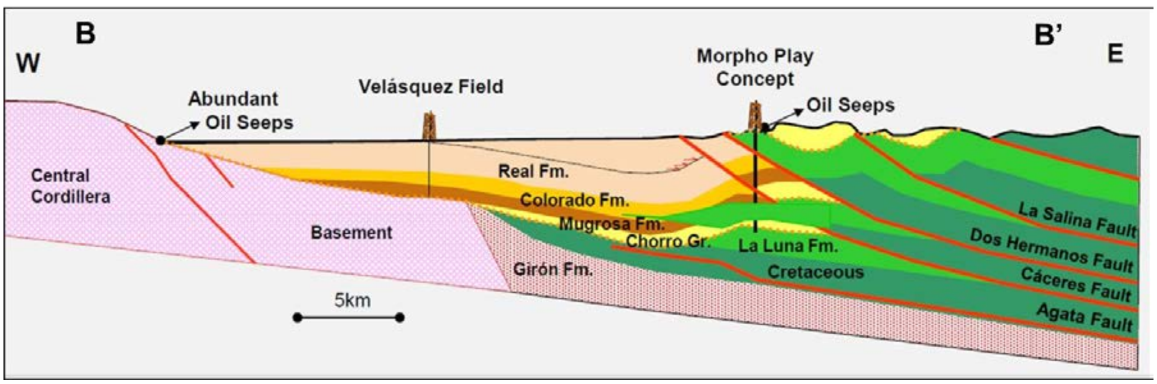
Source: ARI 2013

Figure IV-4: Schematic Cross-Section of the Middle Magdalena Valley Basin Showing U. Cretaceous Umir and La Luna And L. Cretaceous Simiti Shales Totaling 750-1,000 Ft Thick (Correlate With Eagle Ford Shale).



Source: Sintana Energy, Q3 2012

Figure IV-5: Schematic Cross-Section of Western Margin of the Middle Magdalena Valley Basin in Central Colombia, Showing Thrusted Fault Blocks with La Luna Shale.



Source: Platino Energy, 2013

The Cretaceous La Luna Formation is the principal source rock in the MMVB. A marine-deposited black shale, the organic-rich La Luna was formed in a widespread epicontinental sea and is time-equivalent (Santonian) with the Niobrara Shale in the USA.[5] However, sedimentation and facies distribution of the La Luna Fm were strongly controlled by the paleo-topography, while post-depositional tectonics caused erosional events that truncated its thickness in places. For example, much of the Campanian and lower Maastrichtian sections were eroded in the southern Upper Magdalena Valley and Putumayo Basins.[6]

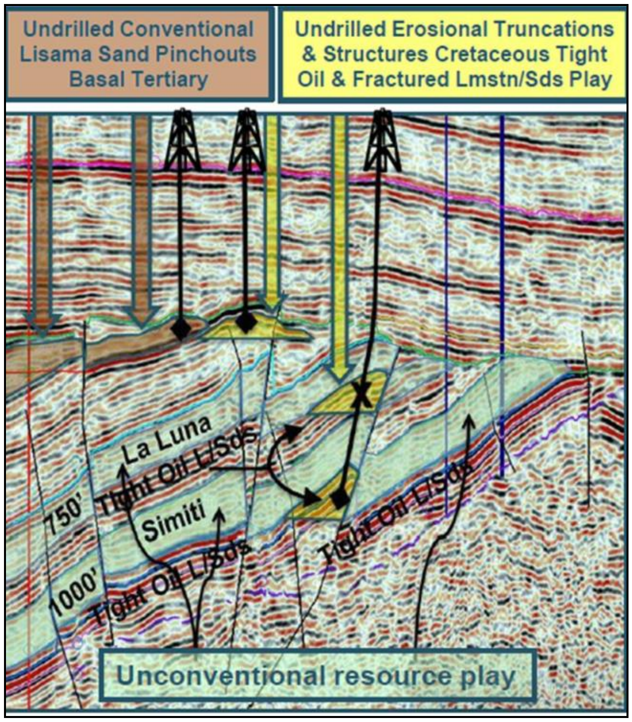
The La Luna Formation comprises three members: the Salada, Pujamana, and Galembo.[7] The most organic-rich (3-12% TOC) is the 150-m thick Salada Member, which consists of hard, black, thinly bedded and finely laminated limy shales (40% $CaCO_3$), along with thin interbeds of black fine-grained limestone. Pyrite veins and concretions are common, as are planktonic (but not benthonic) foraminifera and radiolaria. The lower-TOC Pujamana Member consists of gray to black, thinly bedded and calcareous shale (43% $CaCO_3$). The 220-m thick Galembo Member has moderate TOC (1-4%) and also consists of black, thinly bedded, calcareous shale, but with only thin argillaceous limestone interbeds. The Galembo also has abundant blue to black chert beds.[8] The underlying Cretaceous Tablazo/Rosablanca Fm, about 480-920 ft thick, also contains high TOC (2-8%) that is in the oil to wet gas windows (R_o 0.6% to 1.2%).

1.2 Reservoir Properties (Prospective Area)

The 1,000-ft thick Cretaceous La Luna Formation ranges from 3,000 ft to slightly over 15,000 ft deep across the Middle Magdalena Valley Basin. However, the La Luna is truncated in places by an erosional unconformity, which juxtaposes Paleogene La Paz Fm on top, **Figure IV-6**. The La Luna shale is organic rich (average 5%) with mainly Type II kerogen.[9] We mapped a larger (2,390-mi^2) oil-prone prospective window for the La Luna shale, with a much smaller (200 mi^2) wet gas window to the south (R_o 0.7% to 1.2%).

Calgary-based Canacol Energy Ltd. has noted that the La Luna and Tablazo/ Rosablanca shales are 4,000 to 12,000 ft deep across its blocks in the MMVB . The La Luna ranges from 1,200 to 1,800 ft thick while the underlying Tablazo/Rosablanca is 480 to 920 ft thick. TOC of the two units ranges from 2% to 8% and is mostly at oil-prone thermal maturity (R_o 0.6% to 1.2%). Shale porosity is estimated by Canacol to be 3% to 14%.[10] In 2012 Canacol drilled the Mono Arana-1 well on its VMM 2 block, where it is partnered with ExxonMobil. The well tested shallow conventional targets as well as deeper shale and carbonate potential in the La Luna and Tablazo oil source rocks. Heavy mud, up to 16.5 pounds per gallon, was required to safely drill across these over-pressured shales, indicating they are at nearly twice the normal hydrostatic pressure. The well encountered the top of the La Luna Formation at a depth of 9,180 ft and penetrated 760 ft into the formation, logging oil and gas shows across the entire shale interval. Logs run across the La Luna reportedly indicated 230 ft of potential high-quality net oil pay with 14% average porosity.

Figure IV-6: Seismic Line in the Middle Magdalena Valley Basin Showing Cretaceous La Luna and Simiti Shales Truncated by Erosional Unconformity.



Source: Sintana Energy, Q3 2012

According to Texas-based Sintana Energy the La Luna Formation averages about 1,500 ft thick (gross), has 950-1,900 ft of net pay, 5-10% TOC, 15% effective porosity, and favorably low 17% clay content (should be quite brittle) on the company's blocks in the western MMVB. The underlying Tablazo Formation averages about 600 ft thick (gross), has 150-450 ft of net pay, 5.5-7.0% TOC, 8% effective porosity, and higher 30% clay content. The La Luna in Sintana's area is in the oil window (R_o 0.7-1.0%), while the Tablazo is in the oil to wet gas windows (R_o 1.1%). The pressure gradient ranges from 0.55-0.80 psi/ft in the La Luna to 0.65 psi/ft in the Tablazo.[11]

1.3 Resource Assessment

The risked, technically recoverable shale gas and shale oil resources in the combined Cretaceous La Luna and Tablazo shales of the Middle Magdalena Valley Basin are estimated to be 18 Tcf and 4.6 billion barrels, out of risked shale gas and shale oil in-place of 135 Tcf and 79 billion barrels. By comparison Ecopetrol has estimated the MMV Basin has 29 Tcf of shale gas potential (methodology not disclosed, nor was oil potential noted).

1.4 Recent Activity

A number of companies -- including Ecopetrol, ConocoPhillips, ExxonMobil, Nexen, and Shell -- have initiated shale oil and gas exploration programs at existing conventional oil and gas lease positions in Colombia during the past two years. Activity has been concentrated in the Middle Magdalena Valley Basin, close to the Bogota market. More than 12 vertical and horizontal shale exploration wells were planned for 2012, including several re-entries.

State-owned Ecopetrol S.A., which controls about one-third of the oil and gas licenses in Colombia, first announced its shale exploration program in early 2011 and drilled the La Luna-1 stratigraphic test in the MMVB later that year (results not disclosed). Ecopetrol already has been drilling horizontal wells in the MMVB for non-shale targets during the past several years, providing a good foundation for future horizontal shale development in the basin.[12]

Canacol holds three conventional exploration licenses in Colombia, which the company estimates have a total 260,000 gross acres with shale oil potential. The company has disclosed a Mean Estimate of 2.9 billion barrels of recoverable resource potential within their lease position. In recent months Canacol has signed separate joint-venture agreements with ConocoPhillips, ExxonMobil, and Shell to conduct shale exploration within Canacol's acreage. These companies plan to drill a total of 19 shale exploration wells at an estimated cost of $123 million. ConocoPhillips expects to drill its first exploration well to test the La Luna Shale in the second quarter of 2013.[13] Canacol continues to review the shale potential of two of its other blocks.

Nexen was one of the first companies to report exploring for shale gas in Colombia. The company reports it holds several shale blocks in Colombia for a total 1.5 million acres with shale gas potential.[14] In late 2011 Nexen began drilling the first of four planned shale gas wells. These wells, located in Sueva and Chiquinquira blocks in the Sabana de Bogota high savannah plateau of the Eastern Cordillera mountain range, reportedly target the La Luna Formation. No further details are available.

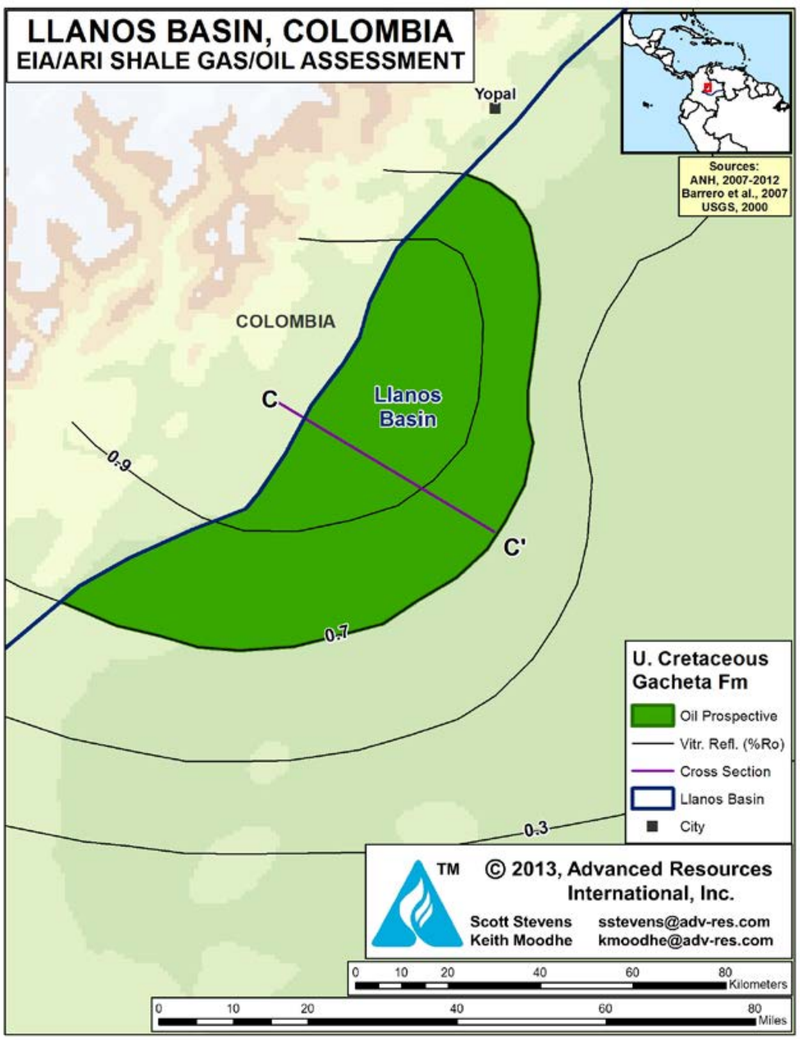
Sintana Energy has reported that its third-party consultant estimated 210 million bbl of prospective recoverable resources in shale formations at the company's VMM-37 block in the MMVB, which cover 44,000 acres (Mean Estimate). Sintana estimated initial horizontal well costs at about $13 million.

2. LLANOS BASIN (COLOMBIA)

2.1 Introduction and Geologic Setting

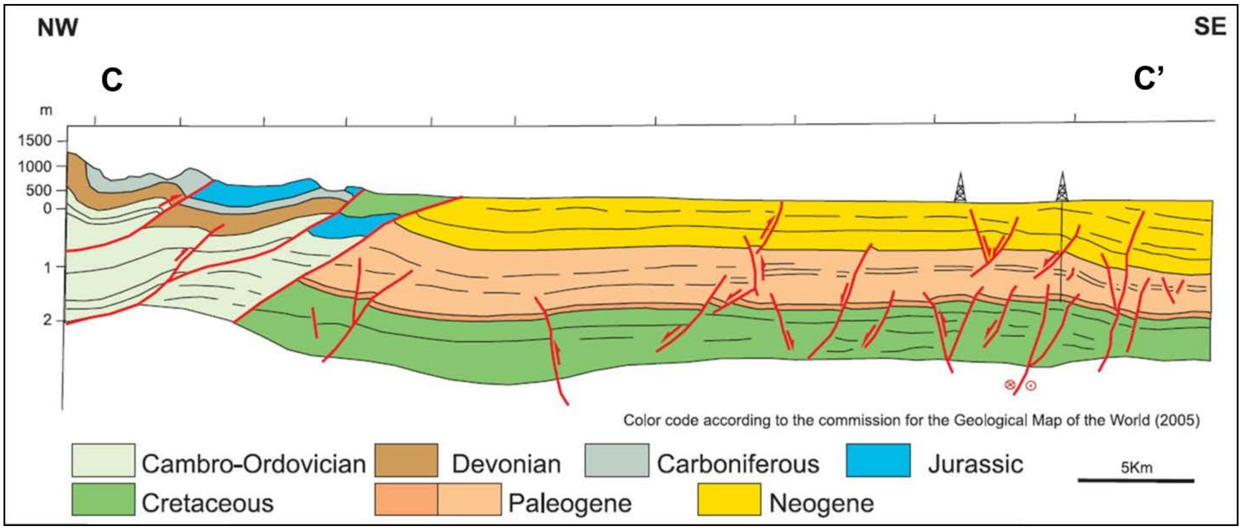
The large (84,000-mi^2) Llanos Basin, located in eastern Colombia, has only recently become a focus of shale exploration and thus is less well understood than the Middle Magdalena Valley Basin, **Figure IV-7**. The Gacheta Fm shale source rocks are equivalent to the La Luna Fm in the MMV and Maracaibo/Catatumbo basins. The northeast-trending Llanos Basin represents the northern extent of the Sub-Andean Mountain Belt. **Figure IV-8** shows the generally simple geologic structure in the interior of the Llanos Basin, as well as the overthrusting on the western margin.

Figure IV-7: Llanos Basin Showing Shale-Prospective Area.



Source: ARI 2013

Figure IV-8: Schematic Cross Section of the Llanos Basin in Colombia



Source : ANH, 2007

Up to 30,000 ft of Cambrian to Ordovician strata are unconformably overlain by thick Cretaceous marine shale deposits. These in turn were partially eroded by uplift during the early Tertiary. Other potential source rocks in the Llanos Basin include the Cretaceous Los Cuervos Fm and Tertiary shales (Carbonera and Leon formations).[15] Conventional reservoirs are found in the Paleogene Carbonera and Mirador sandstones as well as Cretaceous sandstones.

2.2 Reservoir Properties (Prospective Area)

The Cretaceous Gacheta Fm, time-equivalent to the La Luna Fm and averaging 600 ft thick, is the principal source rock in the Llanos Basin. The Gacheta reaches a depth of more than 15,000 ft along the basin's western margin, shoaling to only 2,000 feet in the east. The central axis has the Gacheta shale ranging from 4,000 to over 10,000 ft deep.

The 1,820-mi^2 depth-prospective area is entirely in the oil window. The effective source rock thickness of the Gacheta shale ranges from 150 to 300 ft (average 210 ft net), with TOC of 1% to 3% consisting of Type II and III kerogen.[16] Thermal maturity of the Gacheta ranges from the oil to wet gas windows, with R_o ranging from 0.3% in the shallow east to 1.1% in the deeper western foothills region where the shale oil potential is greatest.[17] Porosity is uncertain but assumed to be relatively high (7%) based on initial data on the correlative La Luna Shale in the MMVB. The basin is slightly over-pressured, averaging about 0.5 psi/ft gradient.

2.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources in the Llanos Basin are estimated to be 2 Tcf of associated shale gas and 0.6 billion barrels of shale oil and condensate, out of risked shale gas and shale oil in-place of about 18 Tcf and 13 billion barrels, **Tables IV-1 and IV-2**. Within the prospective area, the play has a moderate resource concentrations of about 40 Bcf/mi^2 and 28 million bbl/mi^2.

2.4 Recent Activity

No shale exploration leasing or drilling has been reported in the Llanos Basin. Sintana Energy previously mentioned the shale potential of its leases in the Llanos Basin in the company's 2011 investor presentation.

3. MARACAIBO-CATATUMBO BASIN (VENEZUELA, COLOMBIA)

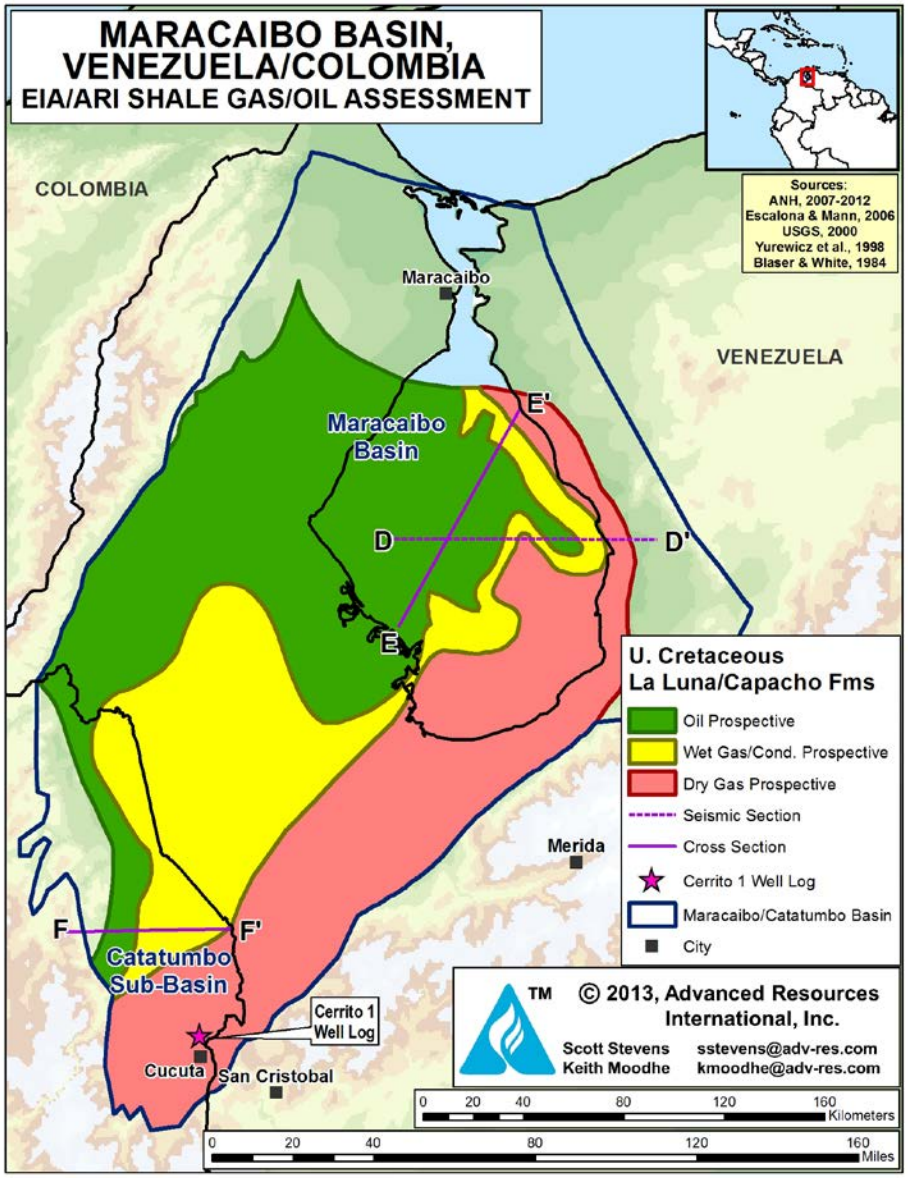
3.1 Introduction and Geologic Setting

The Maracaibo Basin extends over 23,000 mi^2 in western Venezuela and eastern Colombia, the latter area known locally as the Catatumbo Sub-basin, **Figure IV-9**.[18] The Maracaibo/Catatumbo Basin contains a rich sequence of organic-rich marine-deposited Cretaceous shales that are the principal source rocks for prolific conventional fields.[19] These Cretaceous shales, especially the La Luna and Gapacho, appear to be prospective targets for shale oil and gas exploration.

Depth to the Precambrian-Jurassic basement in the Maracaibo Basin reaches over 20,000 feet in southern Lake Maracaibo and its onshore eastern edge, **Figure IV-10**. On the west side of the basin, basement and Cretaceous shale deposits become shallower again, **Figure IV-11**. Depth to the La Luna Fm ranges from less than 5,000 to over 15,000 feet, generally deepening from northeast to southwest. The eastern edge of the shale play is limited by maximum 15,000-ft depth, inferred from the structure of the Late Jurassic basement.[20]

The Catatumbo Sub-basin, located on the rugged east flank of the Andes in eastern Colombia, has similar shale targets but is structurally more complex than the rest of the Maracaibo Basin, with thrust faulting in the west and less severe wrench-faulting in the east, **Figure IV-12**.[21] Much like the northern Maracaibo Basin, the Catatumbo Sub-basin has numerous conventional oil fields.

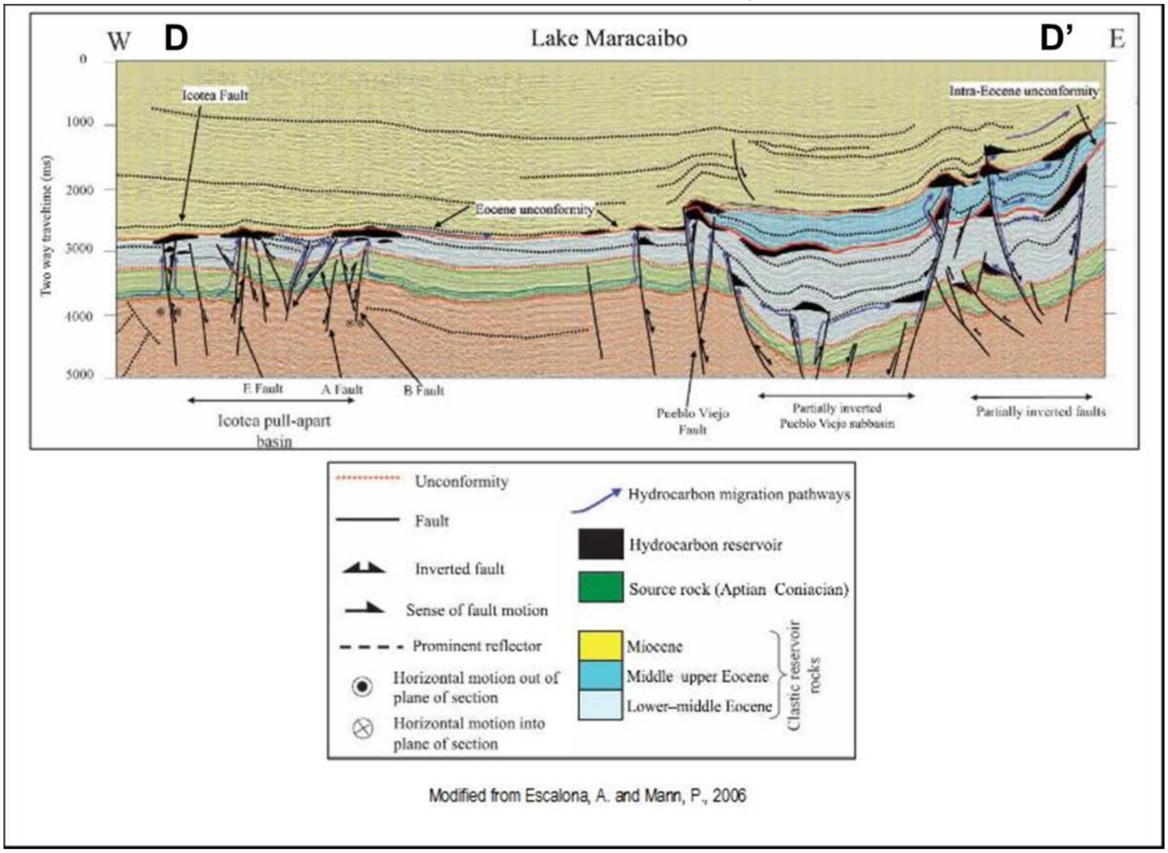
Figure IV-9: Prospective Area for Shale Exploration in the Maracaibo/Catatumbo Basin.



Source : ARI, 2013

Figure IV-10: Seismic Time Section of the Maracaibo Basin in Western Venezuela.

Modified from Escalona and Mann, 2006



Source : ARI, 2013

Figure IV-10: Schematic Cross-Section Showing Depth to Cretaceous Source Rocks in the Maracaibo Basin, Western Venezuela.

Modified from Escalona and Mann, 2006

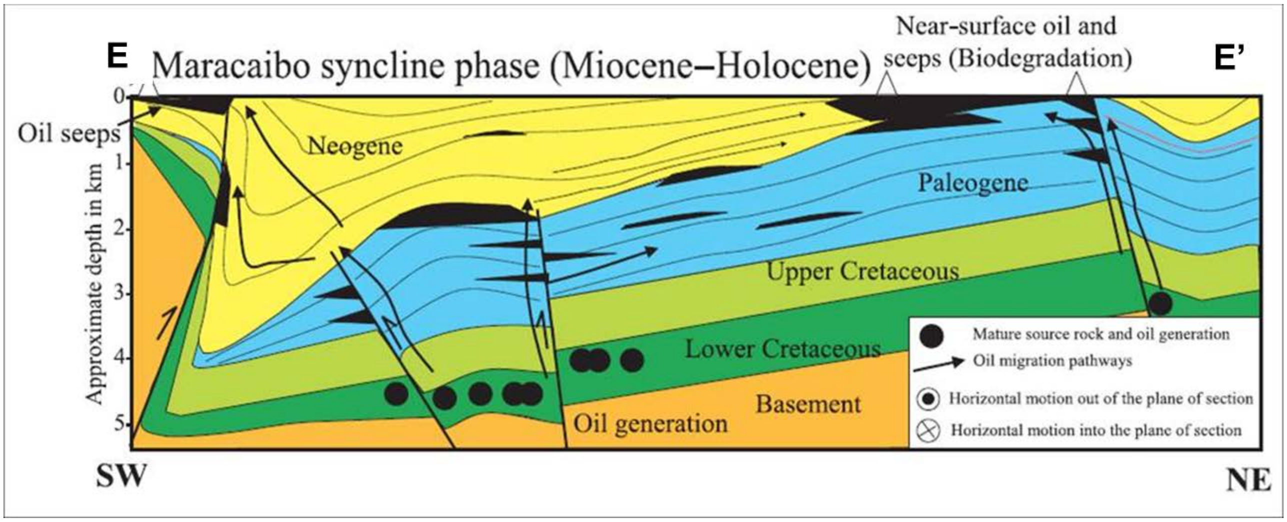
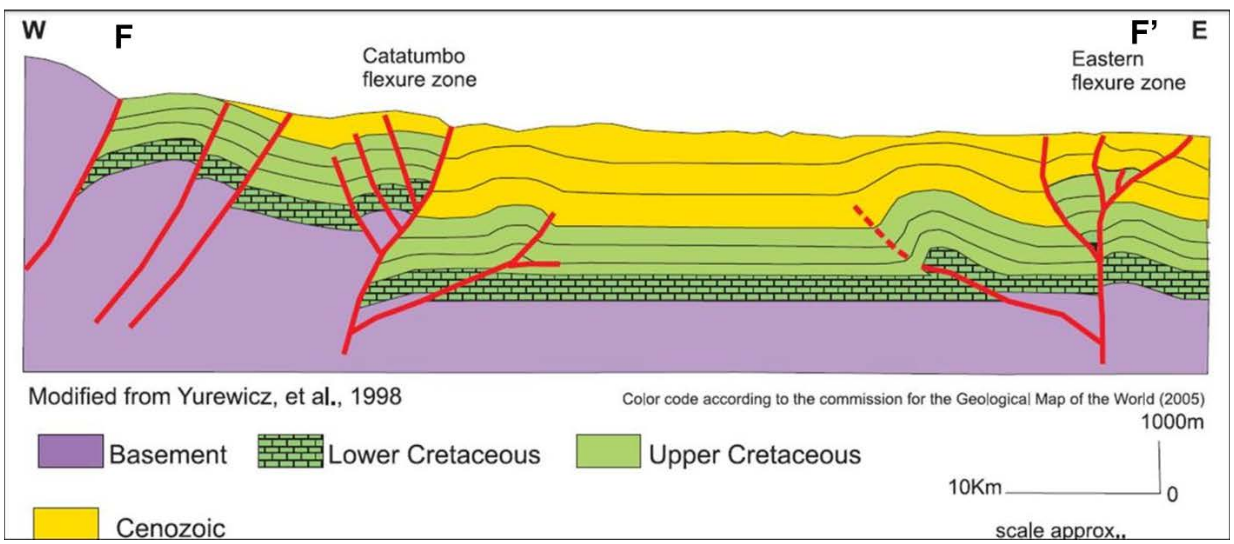


Figure IV-12: Schematic Cross-Section of the Catatumbo Sub-Basin in Eastern Colombia.

Modified from Yurewicz et al., 1998



Advanced Resources International, Inc.

La Luna Formation. The Maracaibo-Catatumbo Basin hosts some of the world's richest source rocks and conventional oil and gas reservoirs. The Late Cretaceous (Cenomanian-Santonian) shale of the La Luna Formation, the primary source rock in the basin[22] and time-equivalent with the Eagle Ford Shale in Texas, appears to be the most prospective target for shale oil and gas exploration. The black calcareous La Luna Shale ranges from 100 to over 400 feet thick across the basin, thinning towards the south and east. [23,24]

Total organic carbon (TOC) varies across the basin, with values ranging from 3.7% to 5.7% in the northwest to 1.7% to 2% in the south and east. Maximum TOC values can reach 16.7%. A large portion of this shale-gas-prospective area includes part of Lake Maracaibo itself. ARI chose to include this submerged area because water depths are shallow (less than 100 feet) and there are numerous conventional production platforms that could provide access to shale drilling and development.

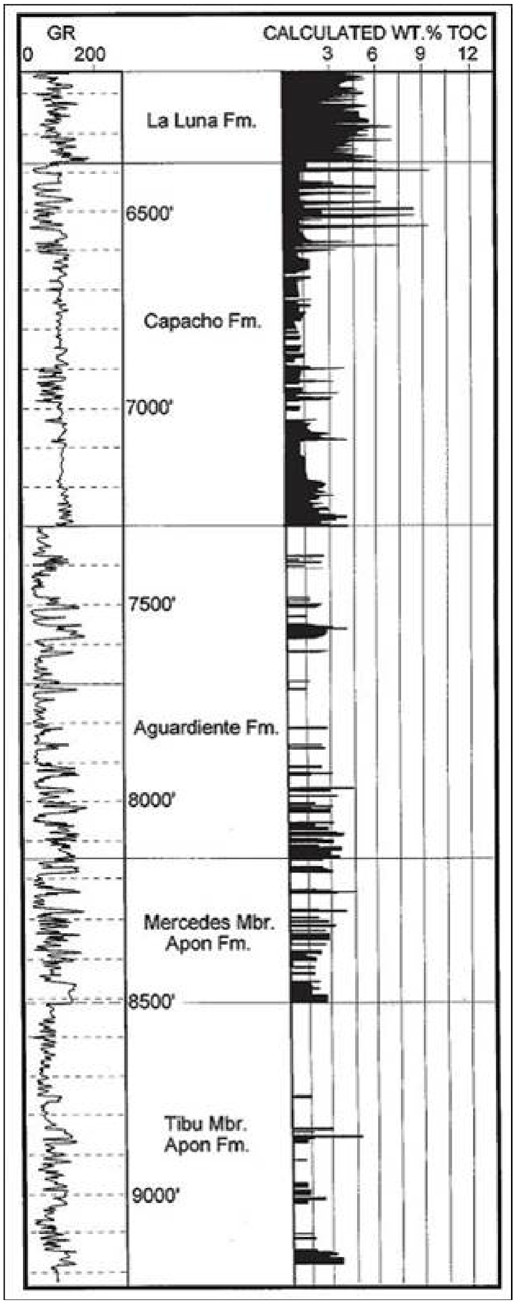
Thermal maturity of the La Luna Fm increases with burial depth from west to east across the Maracaibo Basin, from less than 0.7% R_o to over 1.7% R_o southeast of Lake Maracaibo.[25] Vitrinite reflectance data indicate the unit is mainly in the oil generation window, with a narrow sliver of dry-gas maturity in the east. Note that no significant free gas accumulations have been discovered in the Maracaibo Basin; all natural gas production has been associated gas.

In the much smaller Catatumbo Sub-Basin of Colombia, the La Luna Fm is about 200 ft thick, comprising dark-gray, laminated, limey mudstones and shales with high TOC averaging 4.5% (maximum 11%), mainly Type II with some Type III kerogen.[26] Total organic carbon in core samples reaches a maximum of 11.2% in the La Luna, but more typically averages a still rich 4 to 5% TOC. **Figure IV-13** shows a slight increase in TOC concentration towards the base of the La Luna Fm in the Cerrito 1 well, southeastern Catatumbo Sub-basin.

The La Luna is at relatively shallow depth in the Catatumbo Sub-basin, ranging from 6,000 to 7,600 feet.[27] Based on available vitrinite samples, thermal maturity ranges from 0.85 to 1.21% R_o, with generally higher reflectance in the central and northern areas of the basin. Samples from the Cerro Gordo 3 well in the southeast portion of the Catatumbo Sub-basin averaged 0.85% R_o, indicating that this area is oil prone.

Figure IV-13: Calculated TOC Profile from Well Log in the Catatumbo Sub-Basin.

Modified from Yurewicz et al., 1998



Capacho Formation. The Capacho Formation (Cenomanian-Coniacian) is a distinct unit from the overlying La Luna, although its upper portion is fairly similar. In the Maracaibo basin the Capacho Fm consists of dark-gray to black shales and limestones and is much thicker than the La Luna, ranging from 590 to nearly 1,400 feet in total thickness. However, less data are available on the Capacho. Thus, for this assessment we combined the 200-ft thick, TOC-rich upper portion of the Capacho with the stratigraphically adjacent La Luna for analysis.

Depth to the Capacho ranges from 6,500 feet to 8,500 feet in the Catatumbo Sub-basin, with greater measured depth in the north and east at 8,275 feet in the Socuavo 1 well. TOC reaches 5% in the Socuavo 1 well, northeastern Catatumbo Sub-basin, but more typically is about 1.5%. Kerogen is Type II and III. Vitrinite reflectance ranges from 0.96% R_o in the northern Rio de Oro 14 well to 1.22-1.24% R_o in southeastern well samples.

3.2 Reservoir Properties (Prospective Area)

Three thermal maturity windows were mapped in the Maracaibo/ Catatumbo Basin: dry-gas, wet-gas, and oil. Geologic modeling shows that the present-day temperature gradient in the area ranges from 1.7 and 2.0° F per 100 feet of depth.

Dry Gas Window. Within the 5,840-mi^2 depth-screened, dry-gas thermal maturity window (average 1.6% R_o) of the Maracaibo/Catatumbo Basin, the Cretaceous La Luna Fm and the adjoining upper portion of the Capacho Fm averages about 500 ft thick net, about 12,000 ft deep, and is estimated to have average 5% TOC. Reservoir pressure is uncertain thus assumed to be normal (hydrostatic).

Wet Gas Window. Within the 4,290-mi^2 depth-screened, wet-gas thermal maturity window (average 1.15% R_o), the La Luna and upper Capacho formations average about 11,000 ft deep. Other parameters are similar to the dry gas window.

Oil Window. The La Luna and upper Capacho shales in the thermally less mature portion of the Maracaibo/Catatumbo basin are oil-prone, with average 0.85% R_o. The oil window extends over an area of about 7,280 mi^2 and averages about 10,000 ft deep.

3.3 Resource Assessment

Total risked, technically recoverable shale gas and shale oil resources in the La Luna and Capacho formations of the Maracaibo and Catatumbo basins are estimated to be 202 Tcf and 14.8 billion barrels, out of risked shale gas and shale oil in-place of 970 Tcf and 297 billion barrels, **Tables IV-1 and IV-2**. The play has high a resource concentration of up to 256 Bcf/mi^2 within the dry gas prospective area.

Dry Gas Window. Risked, technically recoverable shale gas resources in the dry-gas window of the Maracaibo/Catatumbo Basin are estimated at 131 Tcf, from a risked shale gas in-place of 523 Tcf. Resource concentration is high (average 256 Bcf/mi^2) due in part to favorable shale thickness and porosity.

Wet Gas Window. The slightly shallower and less thermally mature wet gas window of the Maracaibo/Catatumbo Basin has risked, technically recoverable resources of approximately 53 Tcf of shale gas and 3.1 billion barrels of shale condensate. Risked in-place resources are estimated at 264 Tcf of wet shale gas and 62 billion barrels of shale condensate.

Oil Window. The still shallower and oil-prone window of the La Luna formation and upper Capacho formation in the Maracaibo/Catatumbo basins has an estimated risked, technically recoverable resource of 11.8 billion barrels of shale oil and 18 Tcf of associated shale gas. Risked in-place shale resources are about 235 billion barrels of shale oil and 183 Tcf of shale gas.

3.4 Recent Activity

Junior Canadian E&P Alange Energy Corporation is evaluating the prospectivity of the eastern area of the Catatumbo Sub-basin. However, this exploration activity appears to be focused on conventional reservoirs within the La Luna Shale interval. No shale exploration leasing or drilling has been reported in the Maracaibo Basin.

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