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Technically Recoverable Shale Oil and Shale Gas Resources:

Mexico

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Executive Summary

Introduction

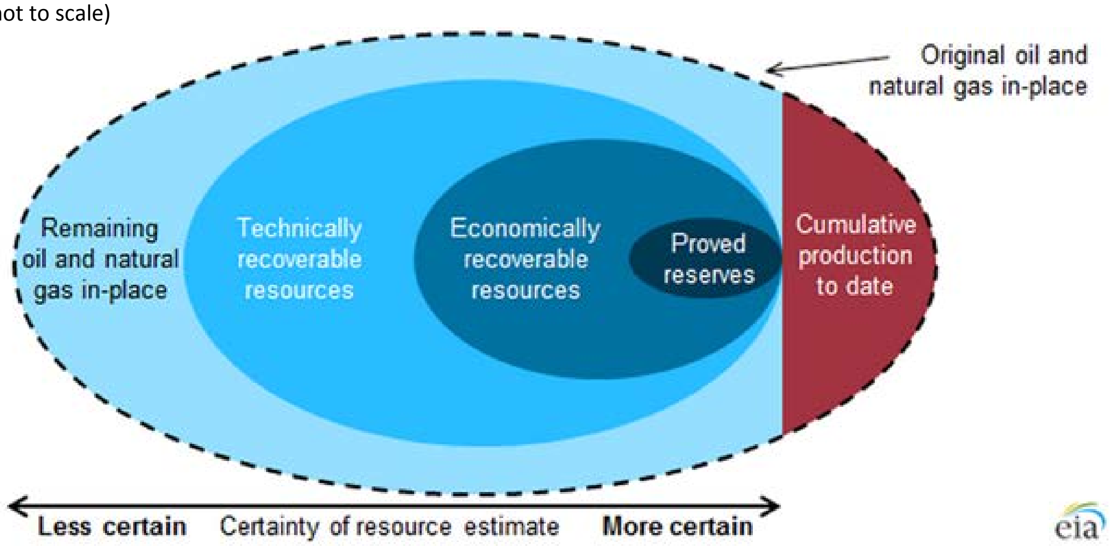
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

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

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

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

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

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:

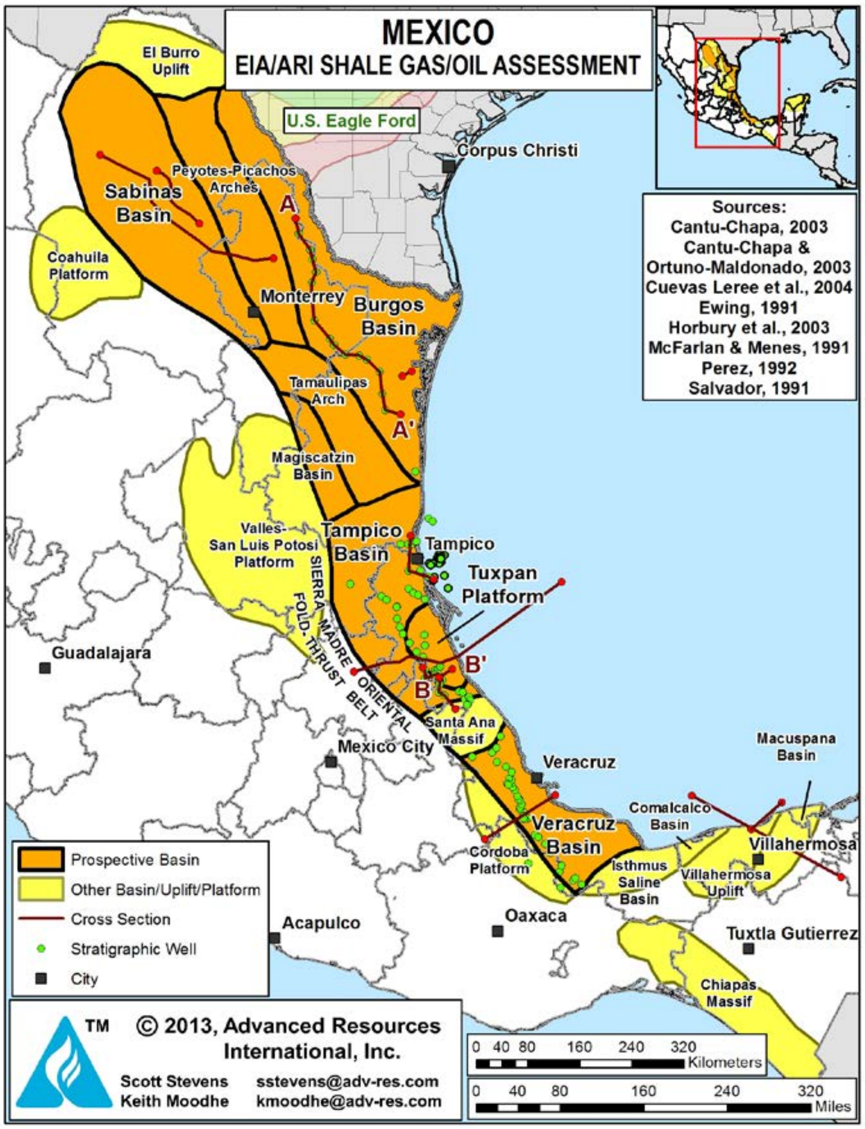
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

II. MEXICO

SUMMARY

Mexico has excellent potential for developing its shale gas and oil resources stored in marine-deposited, source-rock shales distributed along the onshore Gulf of Mexico region.

Figure II-1. Onshore Shale Gas and Shale Oil Basins of Eastern Mexico's Gulf of Mexico Basins.



Source: ARI, 2013.

Technically recoverable shale resources, estimated at 545 Tcf of natural gas and 13.1 billion barrels of oil and condensate, are potentially larger than the country's proven conventional reserves, Table II-1. The best documented play is the Eagle Ford Shale of the Burgos Basin, where oil- and gas-prone windows extending south from Texas into northern Mexico have an estimated 343 Tcf and 6.3 billion barrels of risked, technically recoverable shale gas and shale oil resource potential, Table II-2.

Further to the south and east within Mexico, the shale geology of the onshore Gulf of Mexico Basin becomes structurally more complex and the shale development potential is less certain. The Sabinas Basin has an estimated 124 Tcf of risked, technically recoverable shale gas resources within the Eagle Ford and La Casita shales, but the basin is faulted and folded. The structurally more favorable Tampico, Tuxpan, and Veracruz basins add another 28 Tcf and 6.8 billion barrels of risked, technically recoverable shale gas and shale oil potential from Cretaceous and Jurassic marine shales. These shales are prolific source rocks for Mexico's conventional onshore and offshore fields in this area. Shale drilling has not yet occurred in these southern basins.

PEMEX envisions commercial shale gas production being initiated in 2015 and increasing to around 2 Bcfd by 2025, with the company potentially investing $1 billion to drill 750 wells. However, PEMEX's initial shale exploration wells have been costly ($20 to $25 million per well) and have provided only modest initial gas flow rates (~3 million ft^3/d per well with steep decline). Mexico's potential development of its shale gas and shale oil resources could be constrained by several factors, including potential limits on upstream investment, the nascent capabilities of the local shale service sector, and public security concerns in many shale areas.

Table II-1. Shale Gas Reservoir Properties and Resources of Mexico

Basic Data	Basin/Gross Area		Burgos (24,200 mi^2)				Sabinas (35,700 mi^2)	
	Shale Formation		Eagle Ford Shale			Tithonian Shales	Eagle Ford Shale	Tithonian La Casita
	Geologic Age		M. - U. Cretaceous			U. Jurassic	M. - U. Cretaceous	U. Jurassic
	Depositional Environment		Marine			Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		600	10,000	6,700	6,700	9,500	9,500
	Thickness (ft)	Organically Rich	200	200	300	500	500	800
		Net	160	160	210	200	400	240
	Depth (ft)	Interval	3,300 - 4,000	4,000 - 16,400	6,500 - 16,400	7,500 - 16,400	5,000 - 12,500	9,800 - 13,100
		Average	3,500	7,500	10,500	11,500	9,000	11,500
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Highly Overpress.	Highly Overpress.	Underpress.	Underpress.
	Average TOC (wt. %)		5.0%	5.0%	5.0%	3.0%	4.0%	2.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.60%	1.70%	1.50%	2.50%
	Clay Content		Low	Low	Low	Low	Low	Low
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Dry Gas	Dry Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		21.7	74.4	190.9	100.3	131.9	69.1
	Risked GIP (Tcf)		7.8	446.4	767.5	201.6	501.0	118.1
	Risked Recoverable (Tcf)		0.9	111.6	230.2	50.4	100.2	23.6

Basic Data	Basin/Gross Area		Tampico (26,900 mi^2)			Tuxpan (2,810 mi^2)		Veracruz (9,030 mi^2)	
	Shale Formation		Pimienta			Tamaulipas	Pimienta	Maltrata	
	Geologic Age		Jurassic			L. - M. Cretaceous	Jurassic	U. Cretaceous	
	Depositional Environment		Marine			Marine	Marine	Marine	
Physical Extent	Prospective Area (mi^2)		9,000	3,050	1,550	1,000	1,000	560	400
	Thickness (ft)	Organically Rich	500	500	500	300	500	300	300
		Net	200	200	200	210	200	150	150
	Depth (ft)	Interval	3,300 - 8,500	4,000 - 8,500	7,000 - 9,000	6,000 - 9,500	6,600 - 10,000	9,800 - 12,000	10,000 - 12,500
		Average	5,500	6,200	8,000	7,900	8,500	11,000	11,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		3.0%	3.0%	3.0%	3.0%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.40%	0.85%	0.90%	0.85%	1.40%
	Clay Content		Low	Low	Low	Low	Low	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Assoc. Gas	Assoc. Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		18.6	44.7	83.0	25.5	27.2	22.4	70.0
	Risked GIP (Tcf)		58.5	47.7	45.0	8.9	9.5	6.6	14.7
	Risked Recoverable (Tcf)		4.7	9.5	9.0	0.7	0.8	0.5	2.9

Table II-2. Shale Oil Reservoir Properties and Resources of Mexico

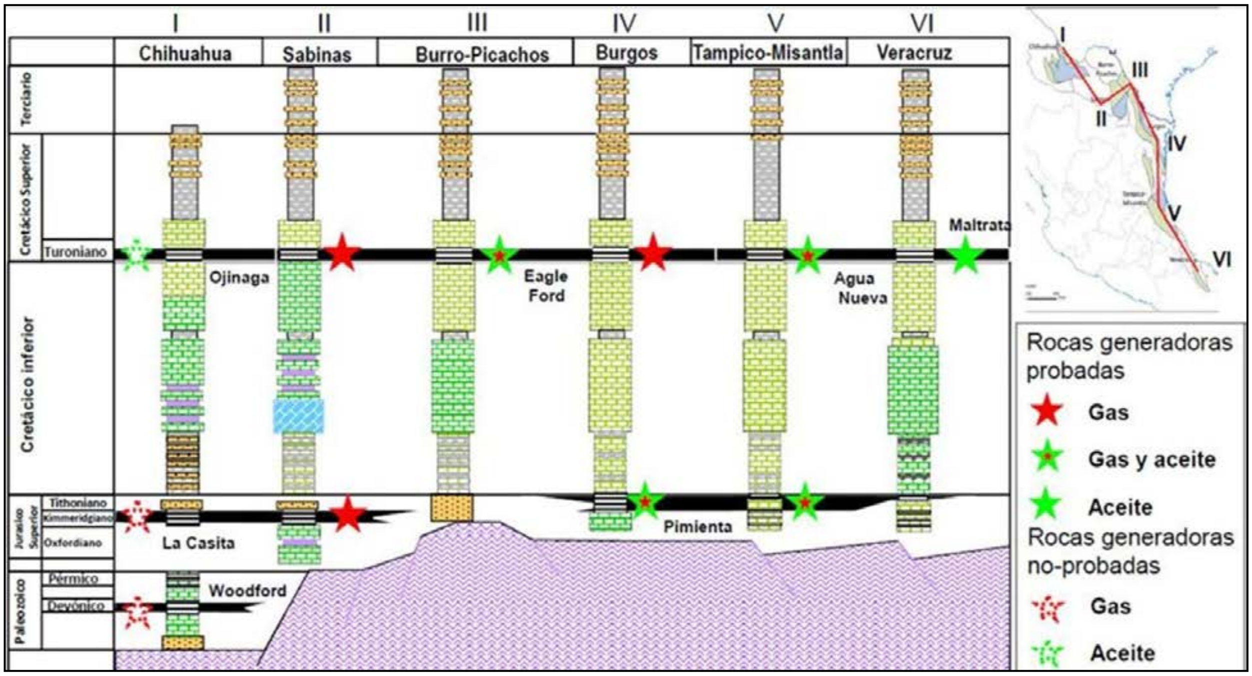
Basic Data	Basin/Gross Area		Burgos ($24,200\ mi^2$)		Tampico ($26,900\ mi^2$)		Tuxpan ($2,810\ mi^2$)		Veracruz ($9,030\ mi^2$)
	Shale Formation		Eagle Ford Shale		Pimienta		Tamaulipas	Pimienta	Maltrata
	Geologic Age		M. - U. Cretaceous		Jurassic		L. - M. Cretaceous	Jurassic	U. Cretaceous
	Depositional Environment		Marine		Marine		Marine	Marine	Marine
Physical Extent	Prospective Area (mi^2)		600	10,000	9,000	3,050	1,000	1,000	560
	Thickness (ft)	Organically Rich	200	200	500	500	300	500	300
		Net	160	160	200	200	210	200	150
	Depth (ft)	Interval	3,300 - 4,000	4,000 - 16,400	3,300 - 8,500	4,000 - 8,500	6,000 - 9,500	6,600 - 10,000	9,800 - 12,000
		Average	3,500	7,500	5,500	6,200	7,900	8,500	11,000
Reservoir Properties	Reservoir Pressure		Highly Overpress.	Highly Overpress.	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		5.0%	5.0%	3.0%	3.0%	3.0%	3.0%	3.0%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%	0.85%	0.90%	0.85%
	Clay Content		Low	Low	Low	Low	Low	Low	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate	Oil	Oil	Oil
	OIP Concentration ($MMbbl/mi^2$)		43.9	15.0	37.9	17.3	36.4	33.0	23.5
	Risked OIP (B bbl)		15.8	89.8	119.4	18.5	12.7	11.5	6.9
	Risked Recoverable (B bbl)		0.95	5.39	4.78	0.74	0.51	0.46	0.28

INTRODUCTION

Mexico has large, geologically prospective shale gas and shale oil resources in the northeastern part of the country within the onshore portion of the greater Gulf of Mexico Basin, Figure II-1. These thick, organic-rich shales of marine origin correlate with productive Jurassic and Cretaceous shale deposits in the southern United States, notably the Eagle Ford and Haynesville shales, Figure II-2.[1] To date, Mexico's national oil company PEMEX has drilled at least six shale gas/oil exploration wells with modest results. The company plans to accelerate shale activity during the next few years, budgeting 6.8 billion pesos (575 million USD) in 2014.

Whereas Mexico's marine-deposited shales appear to have good rock quality, the geologic structure of its sedimentary basins often is considerably more complex than in the USA. Compared with the broad and gently dipping shale belts of Texas and Louisiana, Mexico's coastal shale zone is narrower, less continuous and structurally more disrupted. Regional compression and thrust faulting related to the formation of the Sierra Madre Ranges have squeezed Mexico's coastal plain, creating a series of discontinuous sub-basins.[2] Many of Mexico's largest conventional oil and gas fields also occur in this area, producing from conventional sandstone reservoirs of Miocene and Pliocene age that were sourced by deep, organic-rich and thermally mature Jurassic and Cretaceous-age shales. These deep source rocks are the principal targets for shale gas/oil exploration in Mexico.

Figure II-2. Cross-Section of Shale Targets in Eastern Mexico.



Source: Escalera Alcocer, 2012.

Improved geologic data coverage collected since ARI's initial 2011 estimate indicates that Mexico's prospective areas for shale gas -- particularly in the structurally more complex basins – are slightly smaller than previously mapped. Furthermore, several of the previously mapped dry gas areas are now known to be within the wet gas to oil thermal maturity windows. On the other hand, geologic risk factors have been reduced due to the demonstration of the presence of productive hydrocarbons and improved geologic control. On an overall energy-equivalent basis, our updated estimate of Mexico's shale resources is about 10% lower than our earlier 2011 estimate (624 Tcfe in this study vs 681 Tcf previously).

PEMEX has identified some 200 shale gas resource opportunities in five geologic provinces in eastern Mexico, Figure II-3. According to the company, prospective regions include 1) Paleozoic shale gas in Chihuahua region; 2) Cretaceous shale gas in the Sabinas-Burro-Picachos region; 3) Cretaceous shale gas in the Burgos Basin; 4) Jurassic shale gas in Tampico-Misantla; and 5) unspecified shale gas potential in Veracruz.

Figure II-3. PEMEX Map Identifying Mexico's Shale Gas Potential (November 2012)

Source: PEMEX, 2012b.

PEMEX's initial internal evaluation estimated 150 Tcf (P90) to 459 Tcf (P10) of recoverable shale gas resources, with a median estimate of 297 Tcf. In 2012 PEMEX updated its shale gas and shale oil resource assessment to 141.5 Tcf of shale gas (comprising 104.7 Tcf dry and 36.8 Tcf wet) and 31.9 billion barrels of shale oil and condensate.

Initial shale gas and shale oil exploration began in Mexico in late 2011. PEMEX has drilled at least six wells in the Eagle Ford Shale play in northern Mexico to date, but the southern shale basins have not yet been tested. Despite some areas with favorable shale geology, Mexico faces significant obstacles to shale development. The country's upstream oil industry is largely closed to foreign investment. None of the shale-discovering independent E&P's, which unlocked the North American shale plays, are active in Mexico. And, well services for shale development are costlier than in the U.S. and Canada.

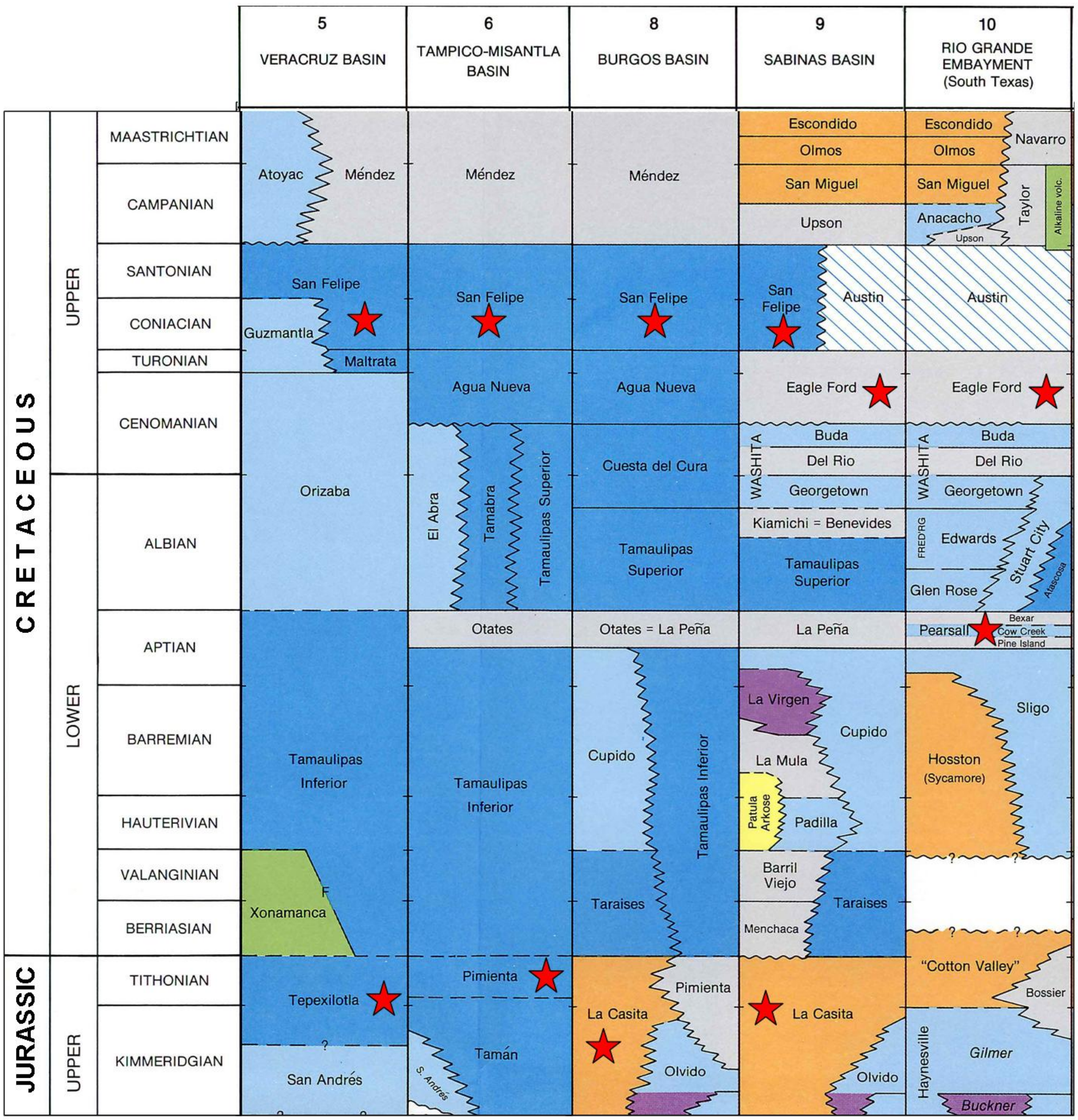
Onshore eastern Mexico contains a series of medium-sized basins and structural highs (platforms) within the larger western Gulf of Mexico Basin.[3] These structural features contain organic-rich marine shales of Jurassic and Cretaceous age that appear to be the most prospective for shale gas and oil development. The arcuate coastal shale belt includes the Burgos, Sabinas, Tampico, Tuxpan Platform, and Veracruz basins and uplifts. Because detailed geologic maps of these areas generally are not readily available, ARI constructed the general pattern of shale depth and thickness from a wide range of published local-scale maps and structural cross-sections.

Many of Mexico's shale basins are too deep in their center for shale gas and shale oil development (>5 km), while their western portions tend to be overthrusted and structurally complex. However, the less deformed eastern portions of these basins and adjacent shallower platforms are structurally more simple. Here, the most prospective areas for shale gas and shale oil development are buried at suitable depths of 1 km to 5 km over large areas.

Pyrolysis geochemistry, carbon isotope studies, and biomarker analysis of oil and gas fields identify three major Mesozoic hydrocarbon source rocks in Mexico's Gulf Coast Basin: the Upper Cretaceous (Turonian to Santorian), Lower-Mid Cretaceous (Albian-Cenomanian), and -- most importantly – Upper Jurassic (Tithonian), the latter having sourced an estimated 80% of the conventional oil and gas discovered in this region.[4] These targets, particularly the Tithonian, also appear to have the greatest potential for shale gas development, Figure II-4.

The following sections discuss the shale gas and shale oil geology of the individual sub-basins and platforms along eastern Mexico's onshore Gulf of Mexico Basin. The basins discussed start in northern Mexico near the Texas border moving to the south and southeastern regions close to the Yucatan Peninsula.

Figure II-4. Stratigraphy of Jurassic and Cretaceous rocks in the Gulf of Mexico Basin, Mexico and USA. Shale gas targets are highlighted.



Modified from Salvador and Quezada-Muneton, 1989.

1. BURGOS BASIN (Eagle Ford and Tithonian Shales)

1.1 Geologic Setting

Located in northeastern Mexico's Coahuila state, directly south of the Rio Grande River, the Burgos Basin covers an onshore area of approximately 24,200 mi^2, excluding its extension onto the continental shelf of the Gulf of Mexico, Figure II-5. The Burgos Basin is the southern extension of the Maverick Basin in Texas, the latter hosting the productive Eagle Ford and Pearsall shale plays.

The Burgos Basin expanded during the Early Jurassic and developed into a restricted carbonate platform, with thick salt accumulations that later formed a regional structural detachment as well as isolated diapirs. Structural deformation took place during the late Cretaceous Laramide Orogeny, resulting in some degree of faulting and tilting within the Burgos Basin. However, this tectonic event was focused more on the Sabinas Basin and Sierra Madre Oriental, while the Burgos remains structurally relatively simple and favorable for shale development.[5] Thick Tertiary-age clastic non-marine deposits overlie the Jurassic and Carbonate marine sequences, reflecting later alternating transgressions and regressions of sea level in northeastern Mexico.[6]

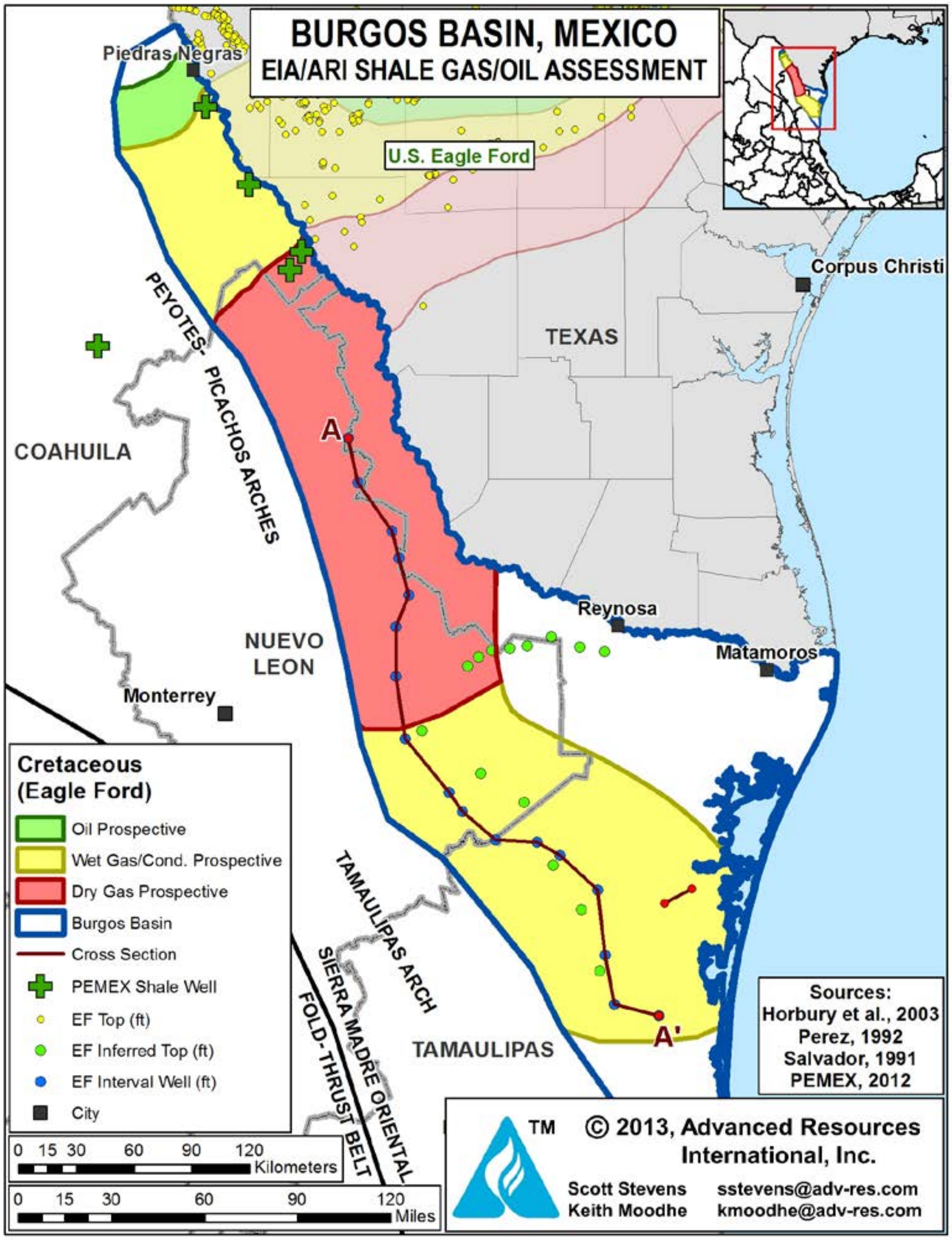
The two most prospective shale targets in Mexico are present in the Burgos Basin: the Cretaceous (mainly Turonian) Eagle Ford Shale play and the Jurassic (mainly Tithonian) La Casita and Pimienta formations, Figure II-6. The Eagle Ford Shale in Mexico is the direct extension of its commercially productive Texas equivalent, whereas the La Casita and Pimienta formations correlate with the productive Haynesville Shale of the East Texas Basin. The La Casita is believed to be the main source rock for conventional Tertiary clastic reservoirs (Oligocene Frio and Vicksburg) in the southeastern Burgos Basin, with oil transported via deep-seated normal faults.[7]

1.2 Reservoir Properties (Prospective Area)

Eagle Ford Shale. Based on analogy with the Eagle Ford Shale in Texas, industry and ARI considers the Eagle Ford Shale in the Burgos Basin to be Mexico's top-ranked shale prospect. The Eagle Ford Shale is continuous across the western margin of the Burgos Basin, where the overall formation interval ranges from 100 to 300 m thick (average 200 m).[8] Recognizing the sparse regional depth and thickness control on the Eagle Ford Shale in the

Burgos Basin,[9] we relied on a recent PEMEX shale map to estimate a prospective area of 17,300 mi², slightly less than our previous estimate of 18,100 mi², comprising three distinct areas where the shale lies within the 1 km to 5 km depth window, Figure II-5. The eastern onshore portion of the Burgos Basin is excluded as the shale is deeper than 5 km.

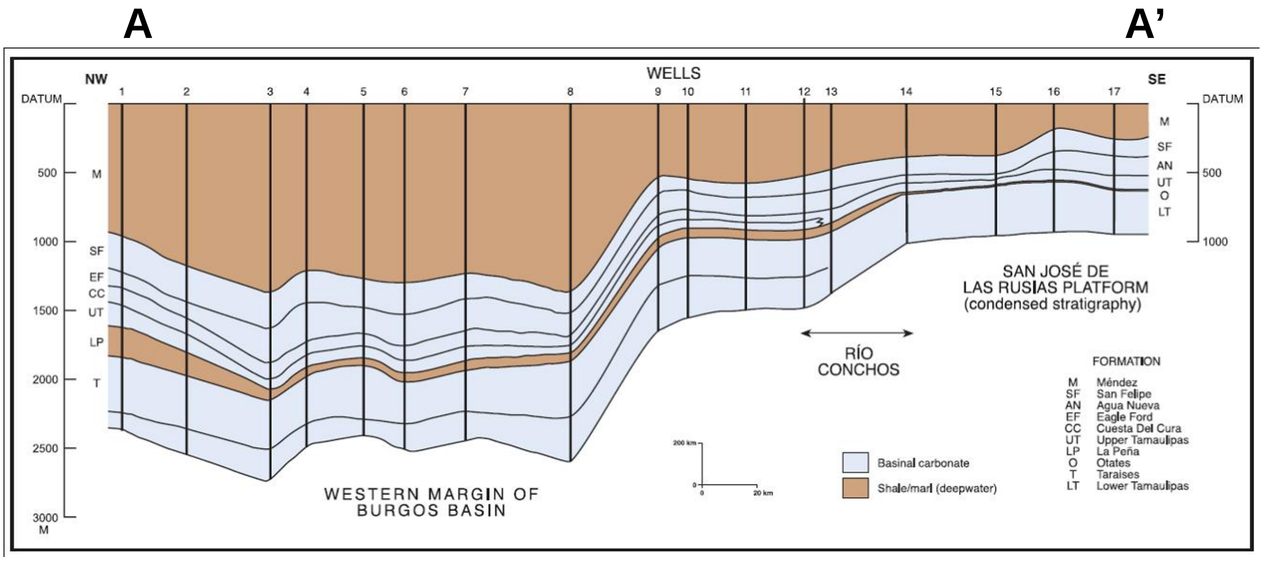
Figure II-5. Burgos Basin Outline and Shale Gas and Shale Oil Prospective Areas.



Source: ARI, 2013.

Figure II-6. Stratigraphic Cross-Section Along the Western Margin of the Burgos Basin.

Section is flattened on top Cretaceous.
The Eagle Ford Shale (EF) here ranges from about 100 to 300 m thick (average 200 m).



Modified from Horbury et al., 2003.

Net organically-rich shale thickness within the prospective area ranges from 200 to 300 ft. Total organic content (TOC) is estimated to average 5%. Vitrinite reflectance (R_o) ranges from 0.85% to 1.6% depending on depth. Over-pressured reservoir conditions are common in this basin and a pressure gradient of 0.65 psi/ft was assumed. The surface temperature in this region averages approximately 20°C, while the geothermal gradient typically is 23°C/km. Porosity is not known but assumed to be comparable to the Texas Eagle Ford Shale play at about 10%.

La Casita and Pimienta (Tithonian) Shales. Several thousand feet deeper than the Eagle Ford Shale, the La Casita and Pimienta shales (Upper Jurassic Tithonian) are considered the principal source rocks in the western Burgos Basin. Extrapolating from the structure of the younger Eagle Ford, the average depth of the Tithonian Shale is 11,500 ft, with a prospective range of 5,000 to 16,400 ft. Gross formation thicknesses can be up to 1,400 ft, with an organically rich net pay of about 200 ft. TOC of 2.6% to 4.0%, averaging 3.0%, consists mainly of Type II kerogen that appears to be entirely within the dry gas window (1.30% R_o) with little to no liquids potential.[10] Reservoir pressure and temperature conditions are similar to those in the Eagle Ford Shale play.

1.3 Resource Assessment

Eagle Ford Shale. Within its 17,300-mi^2 prospective area, the Eagle Ford Shale exhibits a high resource concentration of up to 191 Bcf/mi^2. Risked shale gas in-place (OGIP) totals 1,222 Tcf with risked shale oil in-place (OOIP) of 106 billion barrels. Risked, technically recoverable resources are estimated to be 343 Tcf of shale gas and 6.3 billion barrels of shale oil and condensate.

Tithonian Shale. Within the high-graded prospective area of 6,700 mi^2, the Tithonian La Casita and Pimienta shales are estimated to have approximately 50 Tcf of risked, technically recoverable dry gas resources from 202 Tcf of risked gas in-place. Resource concentration is about 100 Bcf/mi^2.

1.4 Recent Activity

PEMEX initiated conventional exploration in the Burgos Basin in 1942, discovering some 227 mostly natural gas fields in this basin to date. Currently, there are about 3,500 active natural gas wells producing in the Burgos Basin. These conventional reservoirs typically have low permeability with rapidly declining gas production. Due to restrictions on upstream oil and gas investment in Mexico, PEMEX is the only company that has conducted shale exploration activity in the Burgos Basin to date.

PEMEX made its first shale discovery in the Burgos Basin during late 2010 and early 2011, drilling the Emergente-1 shale gas well located a few kilometers south at the Texas/Coahuila border on a continuation of the Eagle Ford Shale trend from Texas. This initial horizontal well was drilled to a vertical depth of about 2,500 m and employed a 2,550-m lateral (although another source reported 1,364-m). Following a 17-stage fracture stimulation, the $20-25 million well tested at a modest initial rate of 2.8 million ft^3/day (time interval not reported), which would not be economic at current gas prices.[11]

As of its last report (November 2012), PEMEX had drilled four shale gas exploration wells in the Eagle Ford play of the Burgos Basin with one shale exploration well in the Sabinas basin, reporting initial production for three wells. These wells include the Nómada-1 well situated in the oil window, the Habano-1 well (IP 2.771 million ft^3/day gas with 27 bbl/day crude) and the Montañés-1 well in the wet gas window of the Burgos Basin. The dry gas window in the Burgos Basin was tested by the Emergente-1. The Percutor-1 (IP 2.17 million ft^3/day) tested the dry gas window in the Sabinas Basin. PEMEX has announced also drilled and produced gas from the Arbolero-1 well (3.2 million ft^3/day), the first test of the Jurassic shale in this basin.[12] PEMEX plans to drill up to 75 shale exploration wells in the Burgos Basin through 2015.

2. SABINAS BASIN (Eagle Ford and Tithonian Shales)

2.1 Geologic Setting

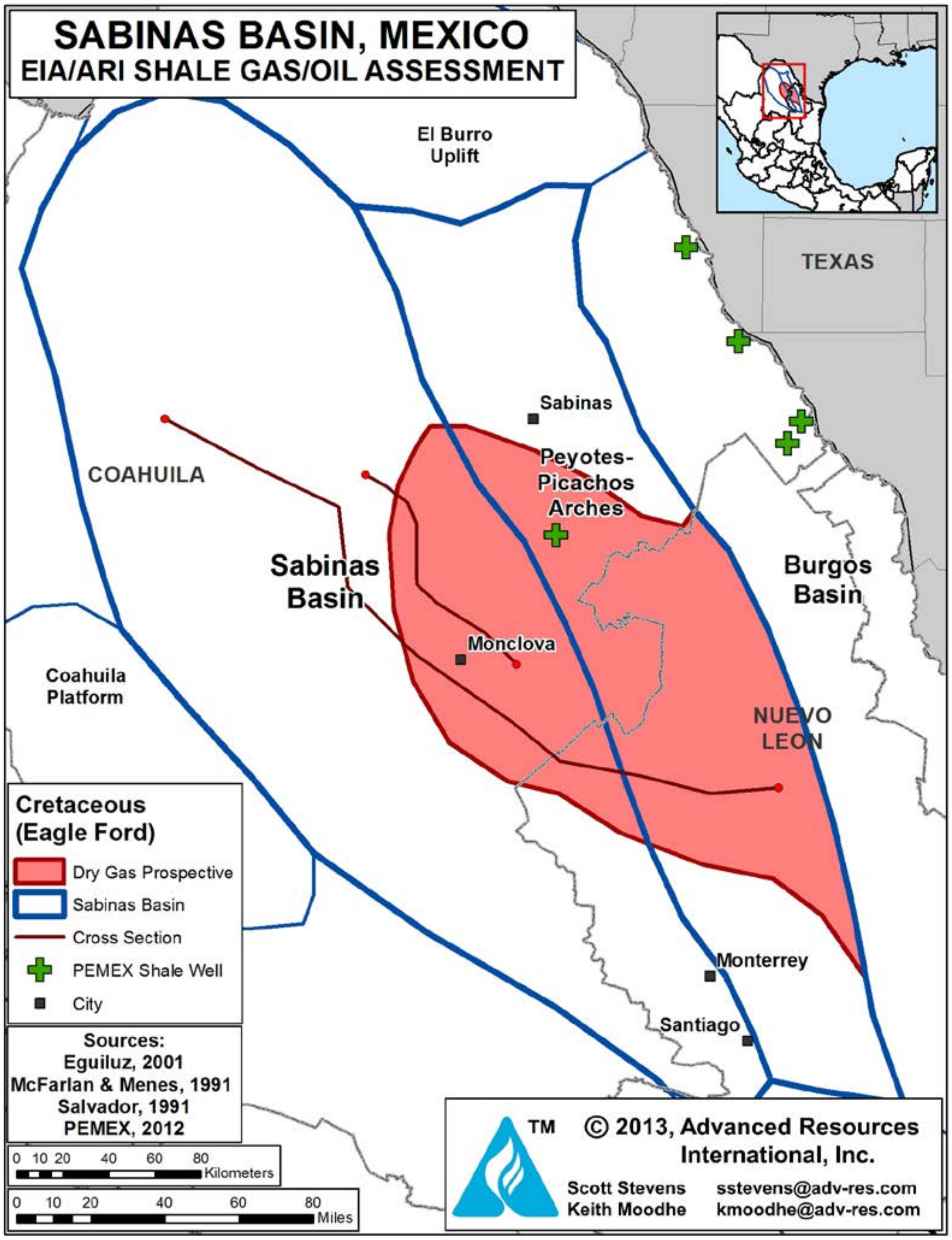
The Sabinas is one of Mexico's largest onshore marine shale basins, extending over a total area of 35,700 mi^2 in the northeast part of the country, Figure II-7. The basin initially expanded during Jurassic time with a northeast-southwest trending structural fabric and was later strongly affected by the Late Cretaceous Laramide Orogeny. Structurally complex, the Sabinas Basin has been deformed into a series of tight, NW-SE trending, evaporate-cored folds of Laramide origin called the Sabinas Foldbelt. Dissolution of Lower Jurassic salt during early Tertiary time introduced a further overprint of complex salt-withdrawal tectonics.[13] Much of the Sabinas Basin is too structurally deformed for shale gas development, but a small area on the northeast side of the basin is more gently folded and may be prospective.

Petroleum source rocks in the Sabinas Basin include the Cretaceous Olmos (Maastrichtian) and Eagle Ford Shale (Turonian) formations and the Late Jurassic (Tithonian) La Casita Formation. The latter two units contain marine shales with good petrophysical characteristics for shale development.[14] In contrast, the Olmos Formation is primarily a non-marine coaly unit that, while a good source rock for natural gas[15] as well as a coalbed methane exploration target in its own right,[16] appears to be too ductile for shale development.

2.2 Reservoir Properties (Prospective Area)

Eagle Ford Shale. The Eagle Ford Shale is distributed across the NW, NE, and central portions of the Sabinas Basin. The target is the 300-m thick sequence of black shales rhythmically interbedded with sandy limestone and carbonate-cemented sandstone. We estimated a 500-ft thick organic-rich interval with 400 feet of net pay. We considered the Eagle Ford Shale in the Maverick Basin of South Texas as the analog for reservoir properties, using a TOC of 4% and a thermal maturity of 1.50% (R_o). Our estimate of porosity was increased to 5% based on the rock fabric and correlation with the Texas Eagle Ford Shale analog. The average depth for the prospective Eagle Ford is approximately 9,000 feet. Based on reported data, mostly from coal mining areas, we use a slightly under-pressured gradient of 0.35 psi/ft for the Sabinas Basin.

Figure II-7. Sabinas Basin Outline and Shale Gas Prospective Area.



Source: ARI, 2013.

La Casita Formation. This Tithonian-age unit, regarded as the primary hydrocarbon source rock in the Sabinas Basin, consists of organic-rich shales deposited in a deepwater marine environment. The La Popa sub-basin is one of numerous sub-basins within the Sabinas Basin, Figure II-8.[17,18] The La Popa is a rifted pull-apart basin that contains thick source rock shales. Up to 370 m of black carbonaceous limestone is present overlying several km of evaporitic gypsum and halite. Total shale thickness in the La Casita ranges from 60 m to 800 m. Thick (300 m) and prospective La Casita Fm shales have been mapped at depths of 2,000 to 3,000 m in the central Sabinas Basin. Nearby, a thicker sequence (400-700 m) was mapped at greater depth (3,000 to 4,000 m).

The high-graded prospective area for the La Casita Formation averages 11,500 ft deep, about 2,500 ft deeper than the Eagle Ford Shale. The La Casita Formation averages about 240 ft of net pay thickness within an 800-ft thick organic-rich interval and has 2.0% average TOC that is gas prone (2.5% R_o). Our estimate of porosity in the La Casita was increased to 5% based on the rock fabric and correlation with the deep Texas and Louisiana Haynesville Shale analog.

2.3 Resource Assessment

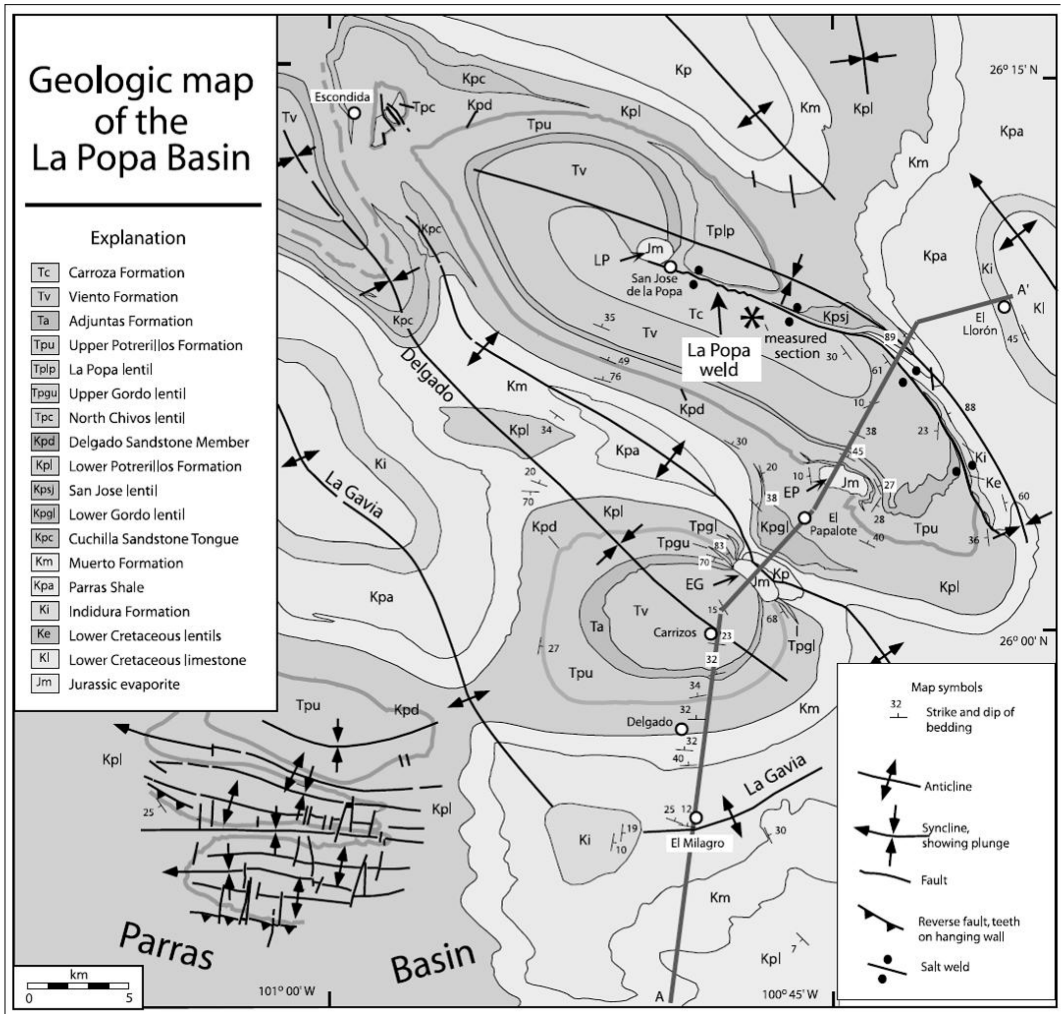
Eagle Ford Shale. The Eagle Ford Shale unit is the larger shale gas target in the Sabinas Basin, with an estimated 100 Tcf of technically recoverable shale gas resource out of 501 Tcf of risked shale gas in-place within the 9,500-mi^2 prospective area. The average resource concentration is high at 132 Bcf/mi^2.

La Casita Formation. The secondary target in the Sabinas Basin, the underlying La Casita Formation, has an estimated 24 Tcf of technically recoverable shale gas out of 118 Tcf of risked shale gas in-place. Its resource concentration is estimated at 69 Bcf/mi^2.

2.4 Recent Activity

PEMEX has drilled one shale gas exploration well in the Sabinas Basin, confirming the continuation of the Eagle Ford Shale play. The Percutor-1 horizontal well, completed in March 2012, produced dry gas from a sub-surface depth of 3,330-3,390 m. The well's initial production rate was a modest 2.17 million ft^3/day (measurement time interval not specified), with production reportedly declining rapidly.

Figure II-8. Geologic Map of the La Popa Sub-Basin, Southeastern Portion of the Sabinas Basin. Note the numerous detachment and salt-controlled folds.



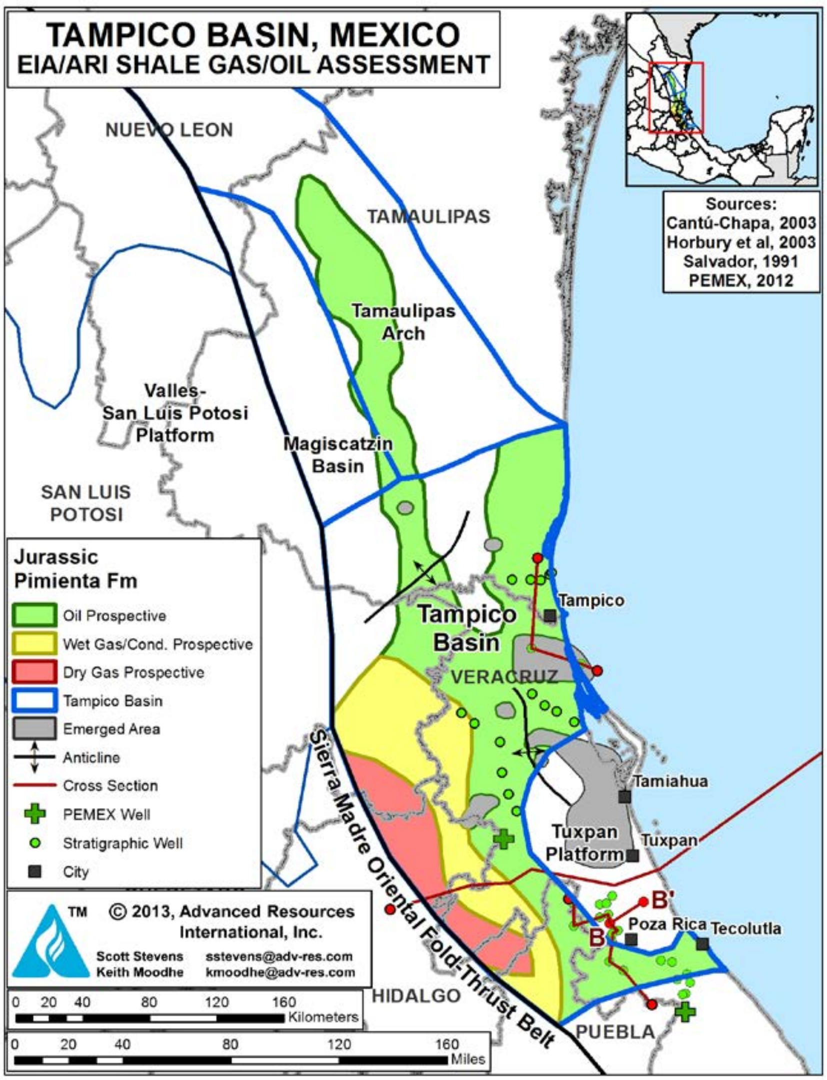
Source: Hudson and Hanson, 2010.

3. TAMPICO BASIN (Pimienta Shale)

3.1 Geologic Setting

Bounded on the west by the fold-and-thrust belt of the Sierra Madre Oriental (Laramide) and on the east by the Tuxpan platform, the Tampico-Mizatlan Basin extends north from the Santa Ana uplift to the Tamaulipas arch north of Tampico, Figure II-9. At the northern margin of the basin is an arch, limited by a series of faults extending south from the Tamaulipas arch.

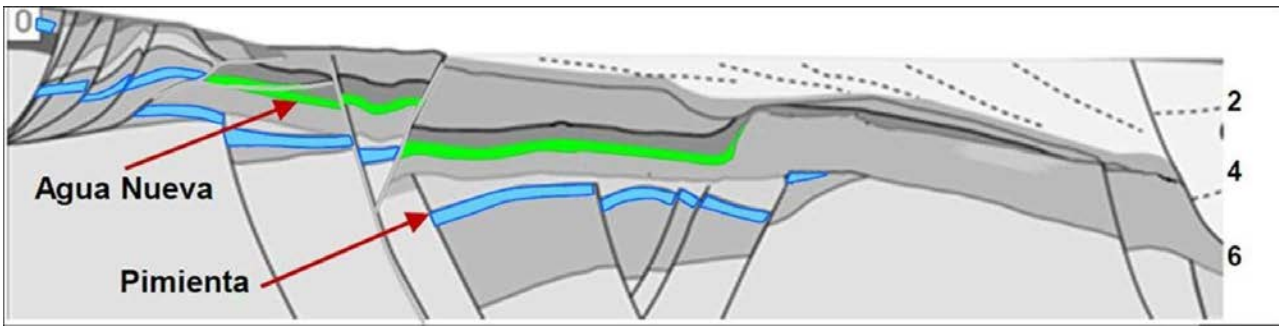
Figure II-9. Prospective Pimienta Formation (Tithonian) Shale, Tampico Basin.



Source: ARI, 2013.

The principal source rock in the Tampico Basin is the Upper Jurassic (Tithonian) Pimienta Shale, Figure II-10. Although quite deep over much of the basin, the Pimienta reaches shale-prospective depths of 1,400 to 3,000 m in the south where three uplifted structures occur. The 40-km long, NE-SW trending Piedra de Cal anticline in the southwest Bejuco area has Pimienta Shale cresting at 1,600-m depth. The 20-km long, SW-NE trending Jabonera syncline in southeast Bejuco has maximum shale depth of 3,000 m in the east and minimum depth of about 2,400 m in the west. A system of faults defines the Bejuco field in the center of the area. Two large areas (Llano de Bustos and La Aguada) lack upper Tithonian shale deposits.

Figure II-10. Structural Cross-Section of the Tampico Basin



Source: Escalera Alcocer, 2012.

3.2 Reservoir Properties

Near the city of Tampico, some 50 conventional wells have penetrated organic-rich shales of the Pimienta Formation at depths of about 1,000 to 3,000 m. Three distinct thermal maturity windows (dry gas, wet gas, and oil) occur from west to east, reflecting the gentle structural dip angle in this basin. Average shale depth ranges from 5,500 to 8,000 ft. Excluding the paleo highs, the prospective area of the Pimienta Shale totals approximately 13,600 mi^2. Detailed shale thickness data are not available, but the Pimienta Fm here generally ranges from 200 m thick to as little as 10 m thick on paleo highs. We estimate an average net shale thickness of about 200 ft, out of the total organically rich interval of 500 ft within the prospective area. Average net shale TOC is estimated at 3%, with average thermal maturity ranging from 0.85% to 1.4% R_o.

3.3 Resource Assessment

The Pimienta Shale in the Tampico Basin holds an estimated 23 Tcf and 5.5 billion barrels of risked, technically recoverable shale gas and shale oil resources, out of risked OOIP and OGIP of 151 Tcf and 138 billion barrels, respectively. The shale gas resource concentration averages 19 to 83 Bcf/mi^2 while the shale oil concentration averages 17 to 38 million bbl/mi^2.

3.4 Recent Activity

PEMEX reported that it is evaluating the shale geology of the Tampico Basin and plans to drill up to 80 shale exploration wells through 2015.[19]

4. TUXPAN PLATFORM (Pimienta and Tamaulipas Shales)

4.1 Geologic Setting

The Tuxpan Platform, located southeast of the Tampico Basin, is a subtle basement high that is capped with a well-developed Early Cretaceous carbonate platform.[20] A particularly prospective and relatively well defined shale gas deposit is located in the southern Tuxpan Platform. Approximately 50 km south of the city of Tuxpan, near Poza Rica, a dozen or so conventional petroleum development wells in the La Mesa Syncline area penetrated thick organic-rich shales of the Pimienta (Tithonian) and Tamaulipus (Lower Cretaceous) Formations.[21]

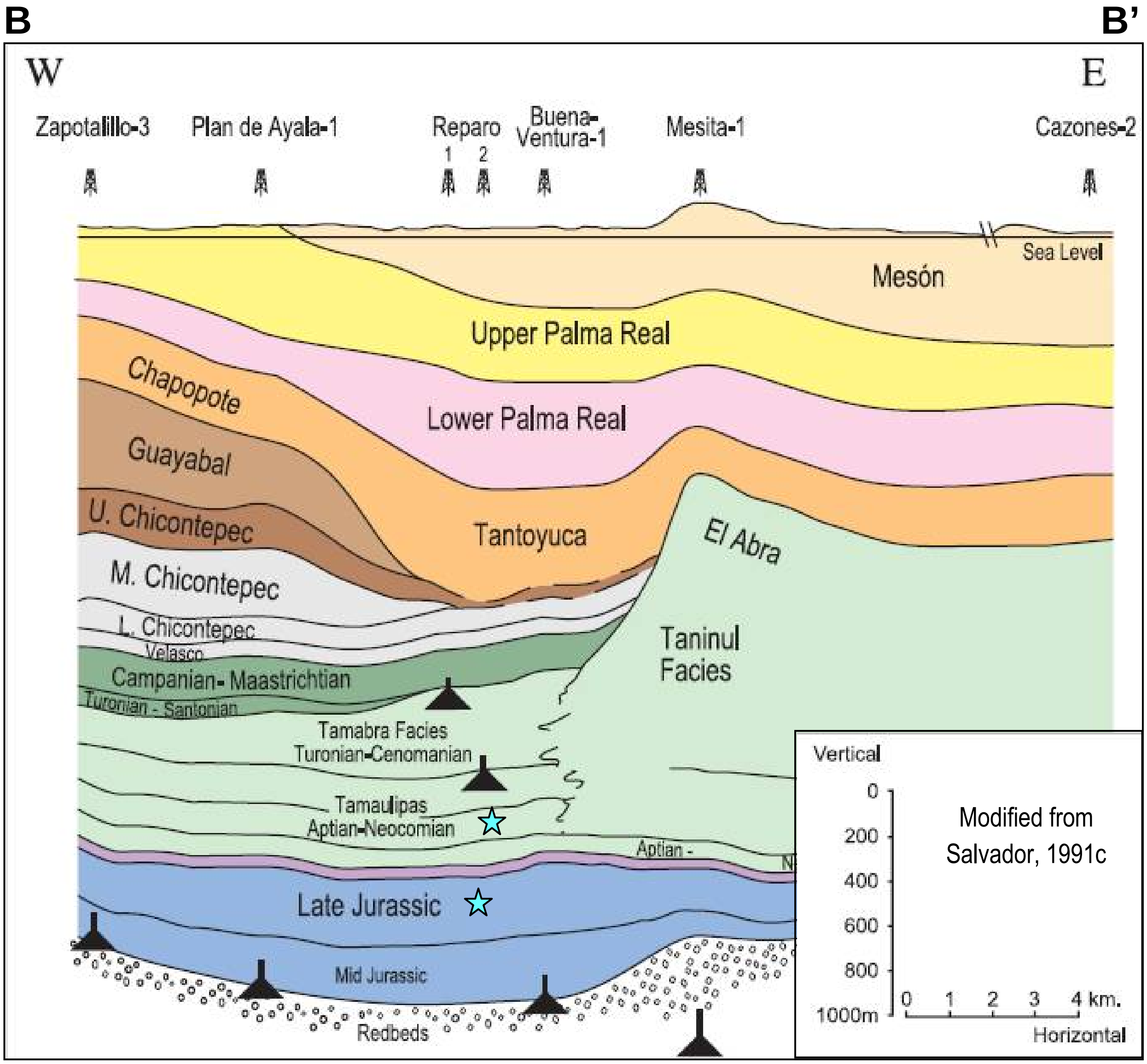
A detailed cross-section of the Tuxpan Platform shows thick Lower Cretaceous and Upper Jurassic source rocks dipping into the Gulf of Mexico Basin, Figure II-11. These source rocks reach prospective depths of 2,500 m. Thermal maturity ranges from oil- to gas-prone.

4.2 Reservoir Properties (Prospective Area)

Pimienta Fm. The organically rich portion of the Jurassic Pimienta Shale averages about 500 ft thick in the high-graded area, with net thickness estimated at 200 ft. However, southeast of Poza Rica some areas the shale is thin or absent, probably due to submarine erosion or lack of deposition, Figure 12. The gamma ray log response in the organic-rich Pimienta Shale indicates moderate TOC of 3.0%, which is in the oil to wet gas window (average R_o of 0.9%). Depth ranges from 6,600 to 10,000 ft, averaging about 8,500 ft.

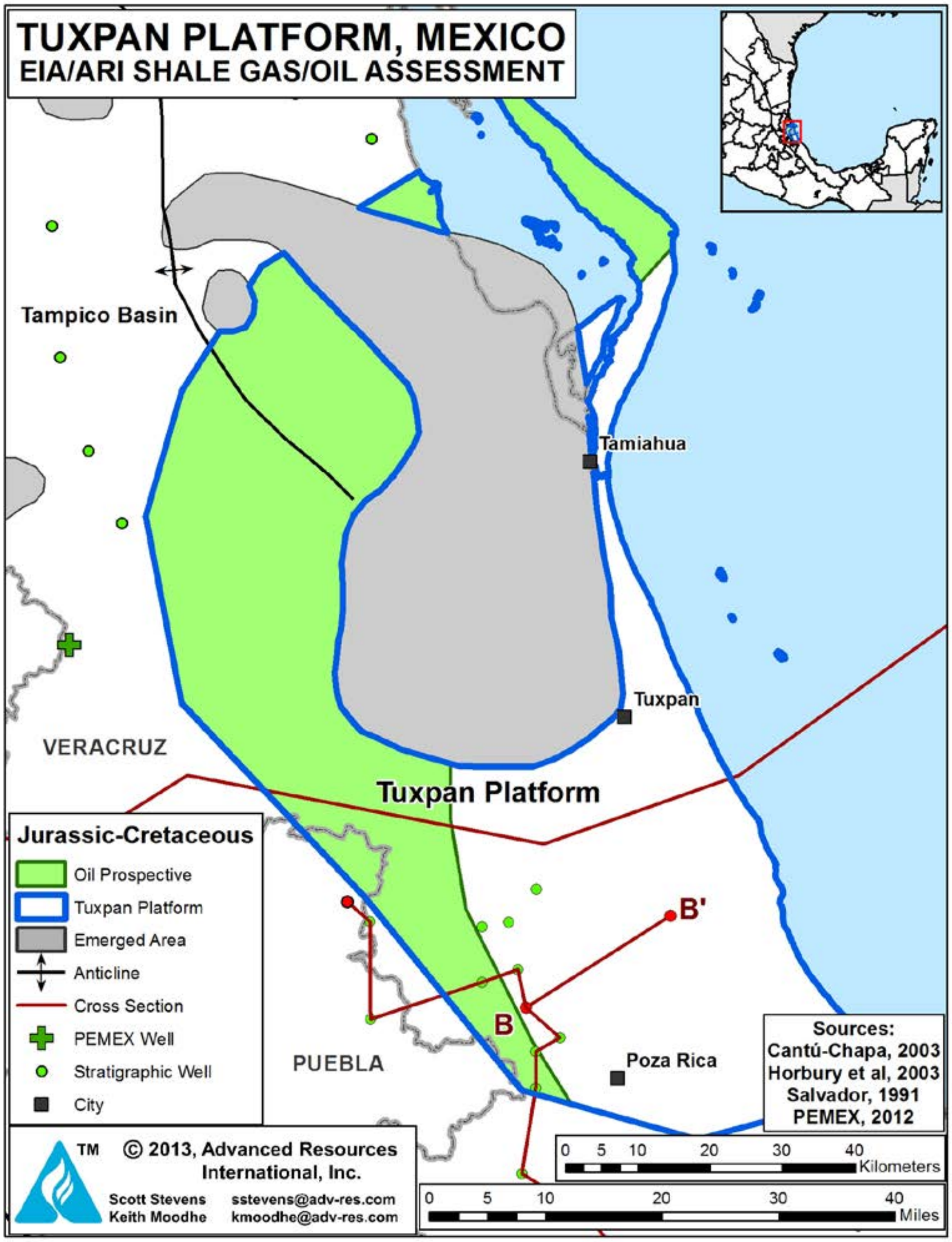
Tamaulipas Fm. The Lower Cretaceous Tamaulipas Fm spans a depth range of 6,000 to 9,500, averaging about 7,900 ft. The organic-rich interval averages 300 ft thick, with net pay estimated at about 210 ft. TOC is estimated to be 3.0%. The average thermal maturity is slightly lower than for the deeper Pimienta, at 0.85% R_o.

Figure II-11. Cross-Section of the Tuxpan Platform.



Modified from Salvador, 1991c.

Figure II-12. Potentially Prospective Shale Gas and Shale Oil Areas of the Tuxpan Platform.



Source: ARI, 2013.

4.3 Resource Assessment

Pimienta Fm. In the Tuxpan Platform, the prospective area of the Pimienta Fm shale is estimated to be approximately 1,000 mi^2. Risked, technically recoverable resources are estimated to be about 1 Tcf of shale gas and 0.5 billion barrels of shale oil and condensate. Risked shale resource in-place is estimated at 10 Tcf and 12 billion barrels.

Tamaulipas Fm. Due to limited data on the younger Tamaulipas Fm the same prospective area of the Pimienta Shale was assumed (1,000 mi^2). The Tamaulipas Shale is estimated to have risked technically recoverable resources of about 1 Tcf of shale gas and 0.5 billion barrels of shale oil and condensate, out of risked shale resources in-place of 9 Tcf and 13 billion barrels.

4.4 Recent Activity

No shale gas or oil exploration activity has been reported on the Tuxpan Platform.

5. VERACRUZ BASIN (Maltrata Shale)

5.1 Geologic Setting

The Veracruz Basin extends over an onshore area of 9,030 mi^2, near its namesake city. The basin's western margin is defined by thrusted Mesozoic carbonates (early Tertiary Laramide Orogeny) of the Cordoba Platform and Sierra Madre Oriental, Figure II-13. The basin is asymmetric in cross section, with gravity showing the deepest part along the western margin, Figure II-14.[22] The basin comprises several major structural elements, from west to east: the Buried Tectonic Front, Homoclinal Trend, Loma Bonita Anticline, Tlacotalpan Syncline, Anton Lizardo Trend, and the highly deformed Coatzacoalcos Reentrant in the south.[23]

A recent shale exploration map released by PEMEX indicates the prospective area of the Veracruz Basin is much smaller than previously assumed in the 2011 EIA/ARI study. This is because the shale is shown to be dipping at a steeper angle than previously mapped. In addition, both shale gas and oil thermal maturity windows are present.

5.2 Reservoir Properties (Prospective Area)

Maltrata Fm. The Upper Cretaceous (Turonian) Maltrata Formation is a significant source rock in the Veracruz Basin, containing an estimated 300 ft of organic-rich, shaly marine limestone. TOC ranges from 0.5% to 8%, averaging approximately 3%, and consists of Type II kerogen. Thermal maturity ranges from oil-prone (R_o averaging 0.85%) within the oil window at depths of less than 11,000 ft, to gas-prone (R_o averaging 1.4%) within the gas window at average depths below 11,500 ft.

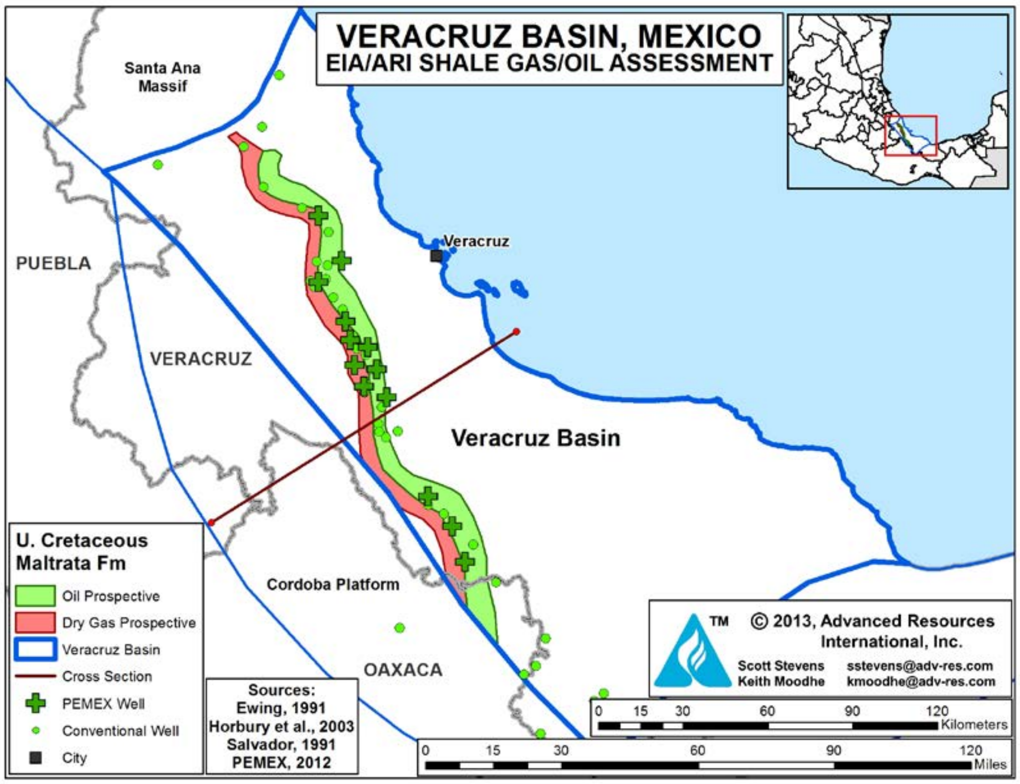
5.3 Resource Assessment

Maltrata Fm. Whereas we previously had assumed that 90% of the Veracruz Basin (8,150 mi^2) is in a favorable depth range, based on available cross-sectional data, the new PEMEX map indicates that the true prospective area in the Veracruz Basin could be much smaller, perhaps only 960 mi^2. This yields a reduced estimate of 3 Tcf and 0.3 billion barrels of risked technically recoverable shale gas and shale oil resources for the Maltrata Formation in the Veracruz Basin, out of 21 Tcf and 7 billion barrels of risked shale gas and shale oil in-place.

5.4 Recent Activity

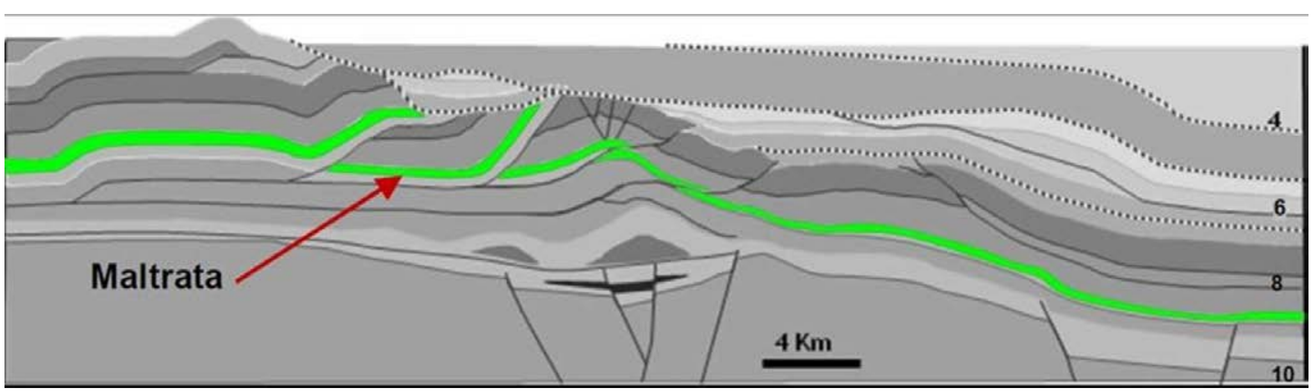
PEMEX plans to drill up to 10 shale exploration wells in the Veracruz Basin in the next three years.

Figure II-13. Veracruz Basin Outline and Shale Gas and Shale Oil Prospective Area.



Source: ARI, 2013.

Figure II-14. Veracruz Basin Cross Section Showing the Maltrata Shale



Source: Escalera Alcocer, 2012.

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