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# Technically Recoverable Shale Oil and Shale Gas Resources: Other South America

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## Executive Summary

### Introduction

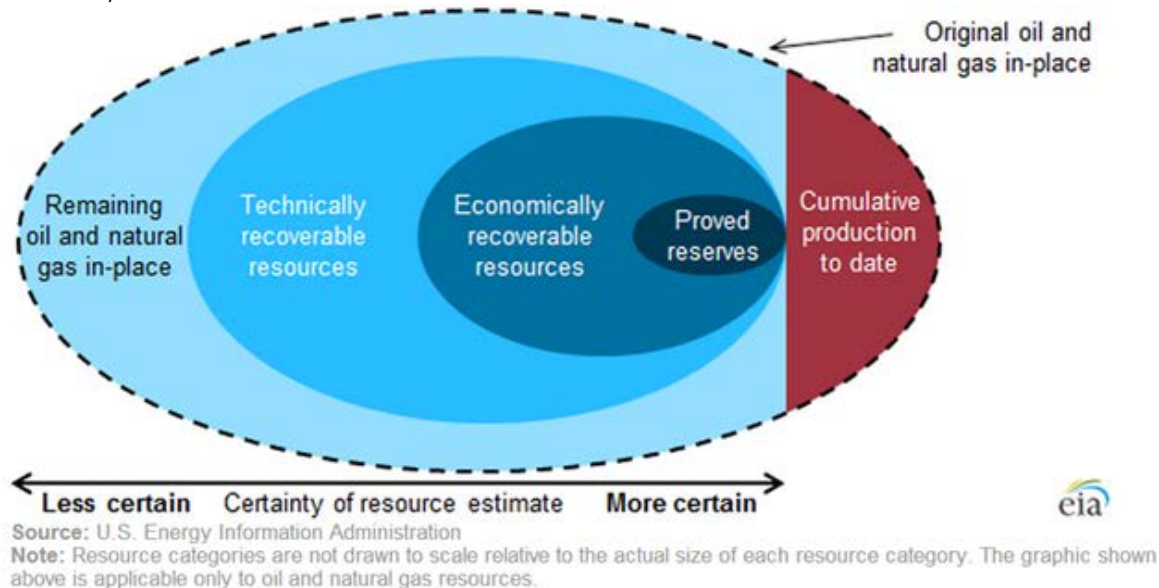
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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



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*<sup>1</sup> and *adsorbed gas*<sup>2</sup> 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.<sup>3</sup> 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<sup>4</sup> 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

<sup>1</sup> 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.

<sup>2</sup> 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.

<sup>3</sup> 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.

<sup>4</sup> 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.



## VII. OTHER SOUTH AMERICA

### SUMMARY

Four other countries in South America (Bolivia, Chile, Paraguay, and Uruguay) have prospective shale gas and shale oil potential within marine-deposited Cretaceous and Devonian shale formations in three large basins: the Paraná Basin of Paraguay and Uruguay; the Chaco Basin of Bolivia and Paraguay; and the Magallanes Basin of Chile, Figure VII-1. (Extensions of these basins within neighboring Argentina and Brazil were assessed in separate chapters.)

Figure VII-1: Prospective Shale Gas and Shale Oil Resources in Bolivia, Chile, Paraguay, and Uruguay.



Source: ARI, 2013

Risked, technically recoverable shale gas and shale oil resources in these four other South American countries are estimated at 162 Tcf and 7.2 billion barrels, Tables VII-1 and VII-2. The geologic setting of this region generally is favorably simple, with mostly gentle structural dip and relatively few faults or igneous intrusions (apart from surface basalt flows). Technically recoverable shale resources by country are: Bolivia (36 Tcf; 0.6 billion barrels); Chile (49 Tcf; 2.4 billion barrels); Paraguay (75 Tcf; 3.7 billion barrels); and Uruguay (2 Tcf; 0.6 billion barrels). Initial shale-related leasing and evaluation has been reported in Paraguay and Uruguay within existing conventional petroleum license areas.

Table VII-1A. Shale Gas Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Parana (747,000 mi <sup>2</sup> )				
	Shale Formation		Ponta Grossa		Cordobes		
	Geologic Age		Devonian		Devonian		
	Depositional Environment		Marine		Marine		
Physical Extent	Prospective Area (mi <sup>2</sup> )		3,830	3,260	2,350	2,690	1,230
	Thickness (ft)	Organically Rich	800	800	800	800	800
		Net	240	240	240	240	240
	Depth (ft)	Interval	10,000 - 11,000	11,000 - 12,000	12,000 - 13,000	3,300 - 5,000	5,000 - 7,000
Average		10,500	11,500	12,500	4,000	6,000	
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	3.6%	3.6%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas
	GIP Concentration (Bcf/mi <sup>2</sup> )		19.9	44.1	71.2	9.7	46.3
	Risked GIP (Tcf)		9.1	17.3	20.1	4.2	9.1
	Risked Recoverable (Tcf)		0.7	3.5	4.0	0.3	1.8

Table VII-1B. Shale Gas Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Chaco (157,000 mi <sup>2</sup> )			Austral-Magallanes (65,000 mi <sup>2</sup> )		
	Shale Formation		Los Monos			Estratos con Favrella		
	Geologic Age		Devonian			L. Cretaceous		
	Depositional Environment		Marine			Marine		
Physical Extent	Prospective Area (mi <sup>2</sup> )		6,870	9,890	14,210	1,580	1,920	1,500
	Thickness (ft)	Organically Rich	1,500	1,500	1,500	800	800	800
		Net	450	450	450	400	400	400
	Depth (ft)	Interval	3,300 - 9,000	7,000 - 12,000	10,000 - 16,400	6,600 - 10,000	10,000 - 14,500	11,500 - 16,400
Average		7,000	10,000	13,000	8,000	12,000	13,500	
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Slightly Overpress.	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		2.5%	2.5%	2.5%	3.5%	3.5%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	0.85%	1.15%	1.60%
	Clay Content		Low	Low	Low	Low/Medium	Low/Medium	Low/Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi <sup>2</sup> )		27.8	86.8	140.5	32.5	114.8	155.9
	Risked GIP (Tcf)		28.7	128.7	299.5	23.1	99.2	105.2
	Risked Recoverable (Tcf)		2.9	25.7	74.9	2.3	19.8	26.3

Table VII-2A. Shale Oil Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Parana (747,000 mi <sup>2</sup> )			
	Shale Formation		Ponta Grossa		Cordobes	
	Geologic Age		Devonian		Devonian	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi <sup>2</sup> )		3,830	3,260	2,690	1,230
	Thickness (ft)	Organically Rich	800	800	800	800
		Net	240	240	240	240
	Depth (ft)	Interval	10,000 - 11,000	11,000 - 12,000	3,300 - 5,000	5,000 - 7,000
Average		10,500	11,500	4,000	6,000	
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	3.6%	3.6%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi <sup>2</sup> )		21.8	9.3	27.7	12.0
	Risky OIP (B bbl)		10.0	3.6	11.9	2.4
	Risky Recoverable (B bbl)		0.40	0.15	0.48	0.09

Table VII-2B. Shale Oil Reservoir Properties and Resources of Bolivia, Chile, Paraguay, and Uruguay.

Basic Data	Basin/Gross Area		Chaco (157,000 mi <sup>2</sup> )		Austral-Magallanes (65,000 mi <sup>2</sup> )	
	Shale Formation		Los Monos		Estratos con Favrella	
	Geologic Age		Devonian		L. Cretaceous	
	Depositional Environment		Marine		Marine	
Physical Extent	Prospective Area (mi <sup>2</sup> )		6,870	9,890	1,580	1,920
	Thickness (ft)	Organically Rich	1,500	1,500	800	800
		Net	450	450	400	400
	Depth (ft)	Interval	3,300 - 9,000	7,000 - 12,000	6,600 - 10,000	10,000 - 14,500
Average		7,000	10,000	8,000	12,000	
Reservoir Properties	Reservoir Pressure		Normal	Normal	Slightly Overpress.	Slightly Overpress.
	Average TOC (wt. %)		2.5%	2.5%	3.5%	3.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	0.85%	1.15%
	Clay Content		Low	Low	Low/Medium	Low/Medium
Resource	Oil Phase		Oil	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi <sup>2</sup> )		46.0	18.7	48.4	14.5
	Risky OIP (B bbl)		47.4	27.7	34.4	12.6
	Risky Recoverable (B bbl)		2.37	1.39	1.72	0.63

## INTRODUCTION

This chapter discusses the shale potential of the other countries in South America (Argentina, Brazil, and Colombia-Venezuela are assessed in separate chapters). As first highlighted in EIA/ARI's 2011 assessment, these other South American countries (Bolivia, Chile, Paraguay, and Uruguay) have significant shale gas and oil resource potential in favorable structural settings. Exploration shale drilling has not yet begun in the region although initial shale leasing and evaluation are underway.

**Bolivia.** A significant natural gas exporter to Argentina and Brazil, Bolivia produces natural gas from conventional reservoirs, mainly in the Chaco Basin in the southeast part of the country. Following 2006 nationalization, YPF administers investment and production in Bolivia's oil and gas sector, while the Ministry of Hydrocarbons and Energy (MHE) and the National Hydrocarbons Agency establish overall policy. Shale exploration or leasing have not been reported in Bolivia.

**Chile.** ENAP, the national oil company of Chile, produces about 5,000 bbl/day mainly from conventional reservoirs in the Magallanes basin.<sup>1</sup> In March 2011 ENAP announced that it will require companies bidding for conventional oil and gas exploration blocks to also explore for shale gas. While exploration is underway for tight gas sandstone reservoirs in the basin, no shale-specific exploration has been reported in Chile.

**Paraguay.** Paraguay does not produce oil and gas, although extensions of its sedimentary basins are productive in both Argentina and Bolivia. Only two conventional petroleum wells have been drilled in Paraguay during the past 25 years. Shale drilling has not occurred in the country but President Energy is investigating the shale potential at its conventional petroleum licenses in the Chaco Basin.

**Uruguay.** Uruguay also does not produce oil and gas, although extensions of its sedimentary basins are productive in neighboring Brazil and Argentina. ANCAP (Administración Nacional de Combustibles, Alcoholes y Portland), the state-owned oil company in Uruguay, administers the country's petroleum licensing. TOTAL, YPF, and others hold leases in the onshore Paraná Basin and are evaluating the shale potential.

Three major sedimentary basins with prospective organic-rich and marine-deposited black shales are present in Bolivia, Chile, Paraguay, and Uruguay, Figure VII-1. These basins, which were assessed in this chapter, are:

- **Paraná Basin** (Paraguay, Uruguay): The Paraná Basin contains black shale within the Devonian Ponta Grossa Formation. The structural setting is simple but the basin is partly obscured at surface by flood basalts, although this igneous cap is less prevalent here than in the Brazil portion of the basin.
- **Chaco Basin** (Paraguay, Bolivia): Black shale in the Devonian Los Monos Formation is present within a relatively simple structural setting in northwest Paraguay. The shale becomes increasingly deep and thrust faulted in southeast Bolivia, where they source that country's prolific conventional reservoirs.
- **Magallanes Basin** (Chile): Known as the Austral Basin in Argentina, the Magallanes Basin of southern Chile contains marine-deposited black shale in the Lower Cretaceous Estratos con Favrella Formation, considered a major source rock in the basin.

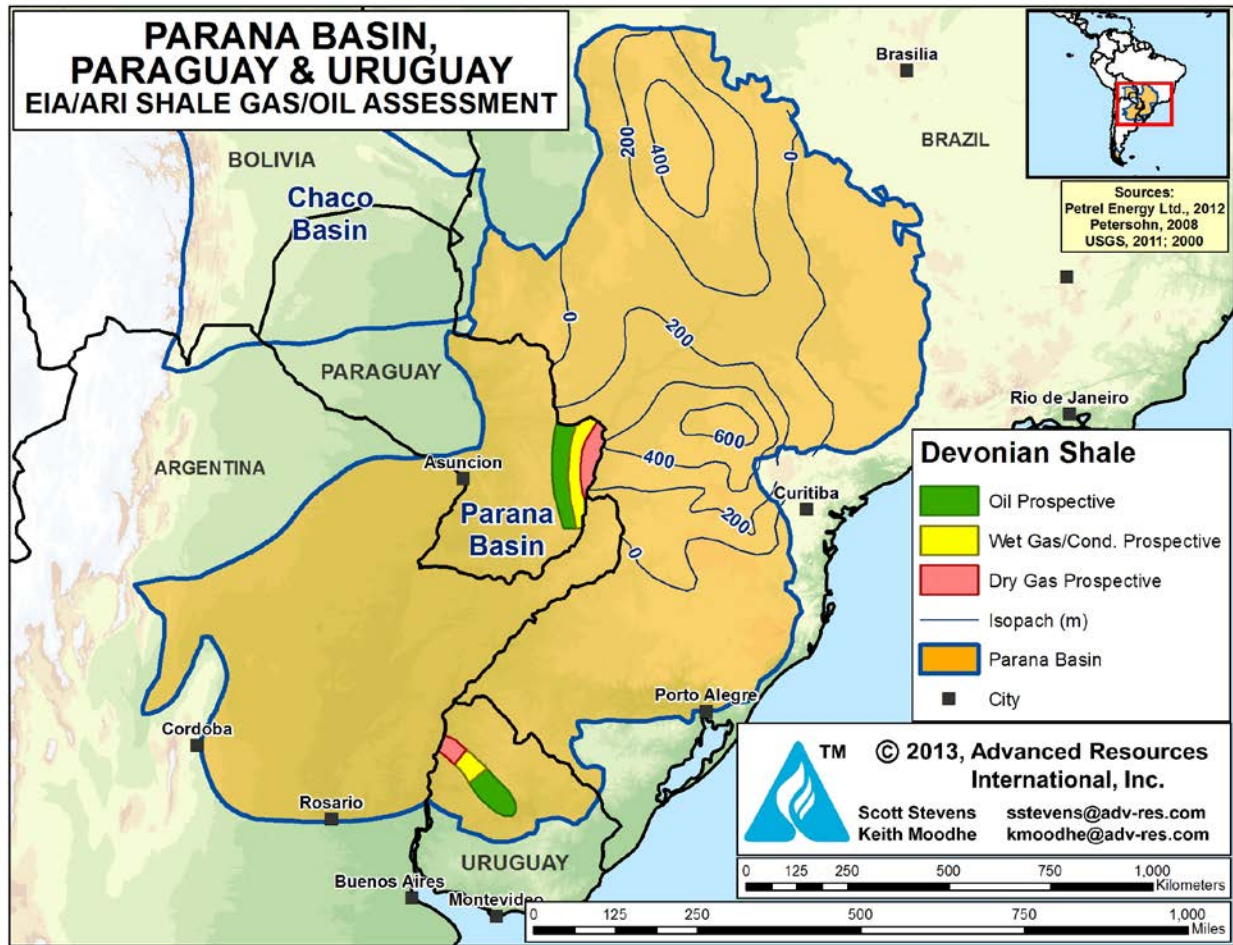
## 1 PARANÁ BASIN (PARAGUAY, URUGUAY)

### 1.1 Introduction and Geologic Setting

The Paraná Basin is a large depositional feature in south-central South America. Most of the basin is located in southern Brazil, but there are significant extensions into Paraguay, Uruguay, and northern Argentina, **Figure VII-2**. This section focuses on the Paraguay and Uruguay portions of the basin. The Paraná Basin contains up to 5 km (locally 7 km) of Paleozoic and Mesozoic sedimentary rocks that range from Late Ordovician to Cretaceous. Its western border is defined by the Asuncion Arch, related to Andean thrusting, while the east is truncated by the South Atlantic tectonic margin.<sup>2</sup> Much of the Brazilian portion of the basin is covered by flood basalts, partly obscuring the underlying geology from seismic and increasing the cost of drilling, but the Paraguay portion is largely free of basalt.

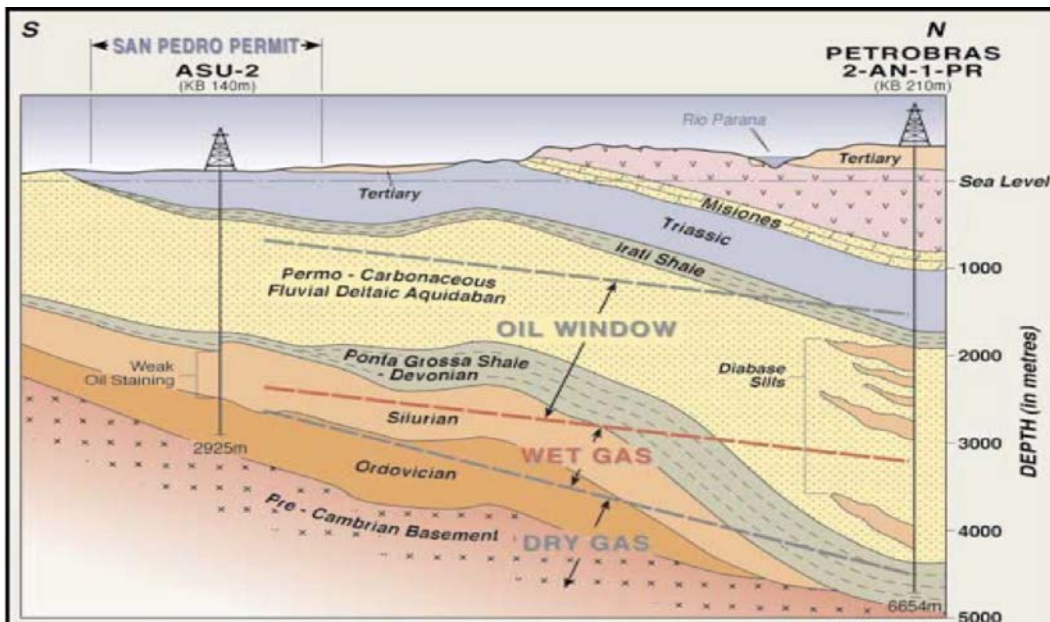
The main petroleum source rock in the Paraná Basin is the Devonian (Emsian/Frasnian) black shale of the Ponta Grossa Formation. The entire formation ranges up to 600 m thick in the center of the basin, averaging about 300 m thick. TOC of the Ponta Grossa Fm reaches up to 4.6% but more typically is 1.5% to 2.5%. The mostly Type II kerogen sourced natural gas that migrated into conventional sandstone reservoirs.<sup>3</sup>

Figure VII-2: Prospective Shale Gas and Shale Oil Areas in the Paraná Basin of Paraguay and Uruguay



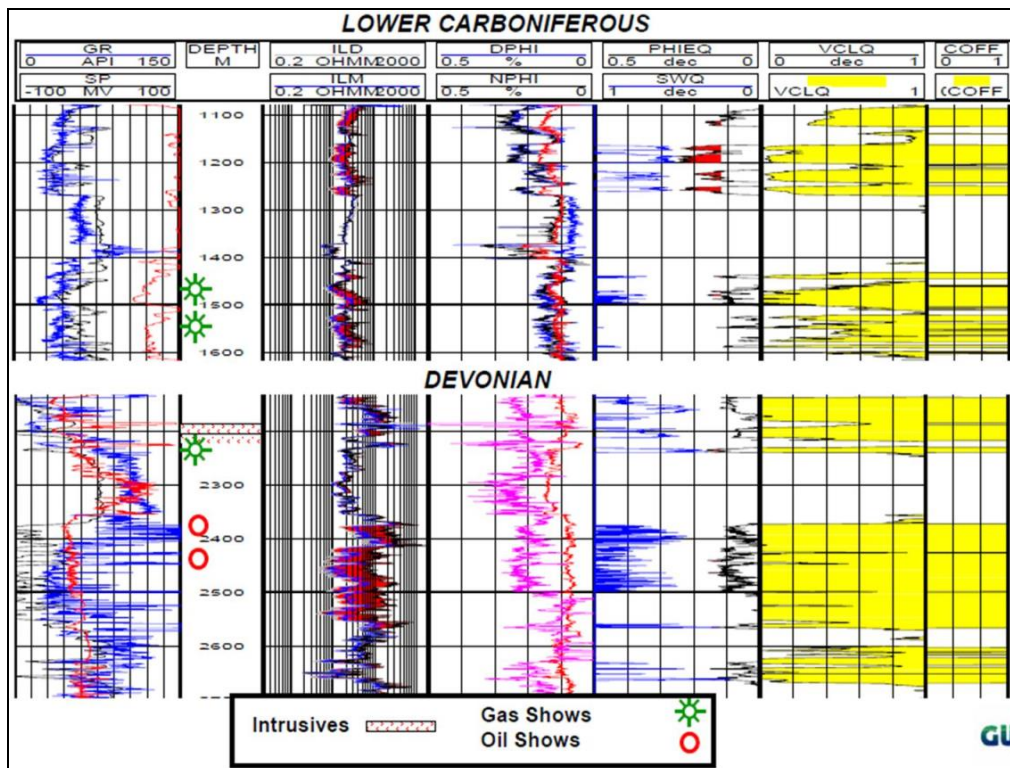
**Figure VII-3**, a cross-section of the Paraná Basin, illustrates the thick and gently dipping Devonian source rocks that pass through the oil window into the gas window.<sup>4</sup> **Figure VII-4**, a conventional well log in the Paraguay portion of the basin, shows Devonian source rocks and interbedded sandstones with oil and gas shows.<sup>5</sup> In outcrop, the Devonian Cordobes Formation ranges up to 160 m thick, including up to 60 m of organic-rich shale. TOC ranges from 0.7 to 3.6%, consisting mainly of Type II marine kerogen. Based on the low thermal maturity at outcrop ( $R_o$  0.6%), ANCAP has estimated the boundary between dry and wet gas to occur at a depth of about 3,200 m.<sup>6</sup>

Figure VII-3: Cross-Section of the Paraná Basin of Paraguay, Showing Thick and Gently Dipping Devonian Source Rocks Passing Through the Oil and Gas Windows.



Source: Chaco Resources PLC, 2004

Figure VII-4: Asuncion-1 Well Log from the Paraná Basin of Paraguay, Showing Devonian Source Rocks and Interbedded Sandstones with Oil and Gas Shows.



Source: Guapex S.A., 2012

The Paraná Basin has remained at moderate burial depth throughout its history. Consequently, the bulk of thermal maturation took place during the late Jurassic to early Cretaceous igneous episode. Most of the basin remains thermally immature ( $R_o < 0.5\%$ ), but there are sizeable concentric windows of oil-, wet-gas-, and dry-gas maturity in the deep central portion of the basin.

## 1.2 Reservoir Properties (Prospective Area)

Depth and thermal maturity of the Devonian Ponta Grossa Formation are relatively well constrained in the Paraguay portion of the Paraná Basin. The prospective area in Paraguay is estimated at 9,440 mi<sup>2</sup>, of which 3,830 mi<sup>2</sup> is in the oil window; 3,260 mi<sup>2</sup> is in the wet gas/condensate thermal maturity window; and 2,350 mi<sup>2</sup> is in the dry gas window.

However, Devonian depth and thermal maturity are much less certain in Uruguay. Uruguay's shale-prospective area is estimated at 3,920 mi<sup>2</sup>, of which 2,690 mi<sup>2</sup> is in the oil window and 1,230 mi<sup>2</sup> is in the wet gas/condensate thermal maturity window (no evidence the Devonian attains dry-gas thermal maturity in Uruguay). The Ponta Grossa shale averages about 240 m thick (net), 10,500 to 12,500 ft deep in Paraguay but only 4,000 to 6,000 ft deep in Uruguay, and averages 2.0% to 3.6% TOC.

Thermal maturity ( $R_o$ ) ranges from 0.85% to 1.5% depending mainly on depth. For example, Amerisur reported that the Devonian Lima Fm has good (2-3%) TOC and is oil-prone ( $R_o$  0.87%) at their conventional exploration block. Porosity is estimated at about 4% and the pressure gradient is assumed to be hydrostatic.

## 1.3 Resource Assessment

Risked, technically recoverable shale gas and oil resources from the Devonian Ponta Grossa Shale in the Paraguay portion of the Paraná Basin are estimated at 8 Tcf of shale gas and 0.6 billion barrels of shale oil and condensate, Tables VII-1 and VII-2. Uruguay has further estimated resources of 2 Tcf of shale gas and 0.6 billion barrels of shale oil and condensate in this play. Risked shale gas and shale oil in-place in Paraguay and Uruguay are estimated at 60 Tcf and 28 billion barrels. The play has low-moderate net resource concentrations of 10 to 71 Bcf/mi<sup>2</sup> for shale gas and 9 to 28 million bbl/mi<sup>2</sup> for shale oil, depending on thermal maturity window.



The USGS recently estimated that Uruguay's portion of the Paraná Basin (Norte Basin) has 13.4 Tcf of shale gas and 0.5 billion barrels of shale oil resources in the Devonian Cordobes Formation. They noted that the sub-basalt extent of inferred deep grabens for their study was imaged by ANCAP using geophysical methods, with no well control.<sup>7</sup> Petrel Energy recently noted that new data indicates the Devonian is less thermally mature than mapped by the USGS.<sup>8</sup> The EIA/ARI thermal windows were adjusted accordingly.

## 1.4 Recent Activity

TOTAL, YPF, and small Australia-based Petrel Energy hold large exploration licenses with Devonian shale potential in the Uruguay portion of the Paraná Basin (Norte Basin). No shale-focused drilling has occurred in Uruguay, nor has shale leasing or drilling activity been reported in the Paraguay portion of the Paraná Basin.

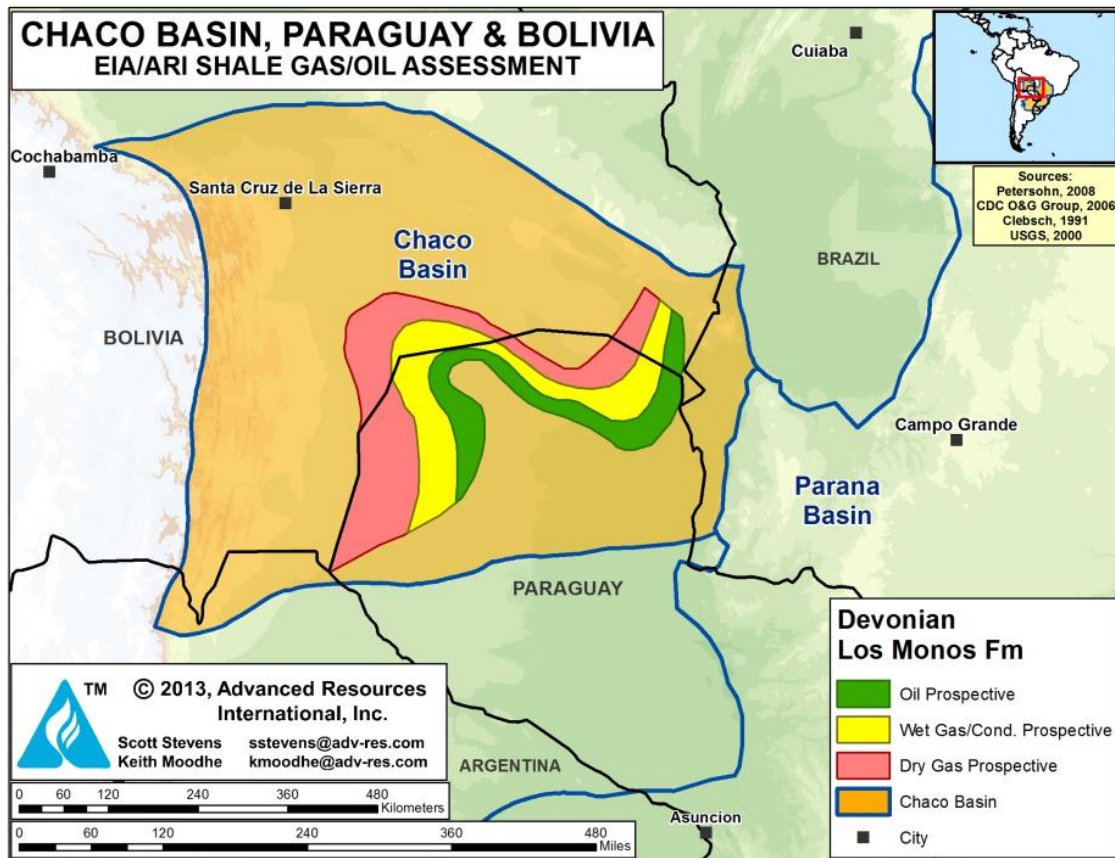
## 2 CHACO BASIN (BOLIVIA, PARAGUAY)

### 2.1 Introduction and Geologic Setting

The large (157,000-mi<sup>2</sup>) Chaco Basin is an intra-cratonic foreland basin broadly similar in origin to the Neuquen and other South American basins east of the Andes Mountains, **Figure VII-5**. The Chaco Basin extends across southeast Bolivia and northwest Paraguay, as well as southern Brazil and northern Argentina (please see separate chapters for these countries). Structural highs (Ascuncion Arch) separate the Chaco Basin from the Parana Basin to the southeast. Structure is relatively simple, with scattered mainly vertical normal faults and none of the thrusting typical of Andean tectonics further to the west.

Sub-basins include the Purity, Carandayty, and Curupayty troughs. Oil and gas production occurs in Bolivia and Argentina but not in Paraguay, which has experienced much less drilling. Fewer than 10 petroleum wells have been drilled in the Purity Sub-basin of Paraguay, all pre-1987, where no commercial production has occurred. However, the Argentina portion of the Basin (Olmedo Sub-basin) has produced over 110 million bbls of oil from the Upper Cretaceous Yacoraite and Palmer Largo formations and that basin continues to be productive.<sup>9</sup> Apart from the international border, no geologic discontinuity separates the two sub-basins.

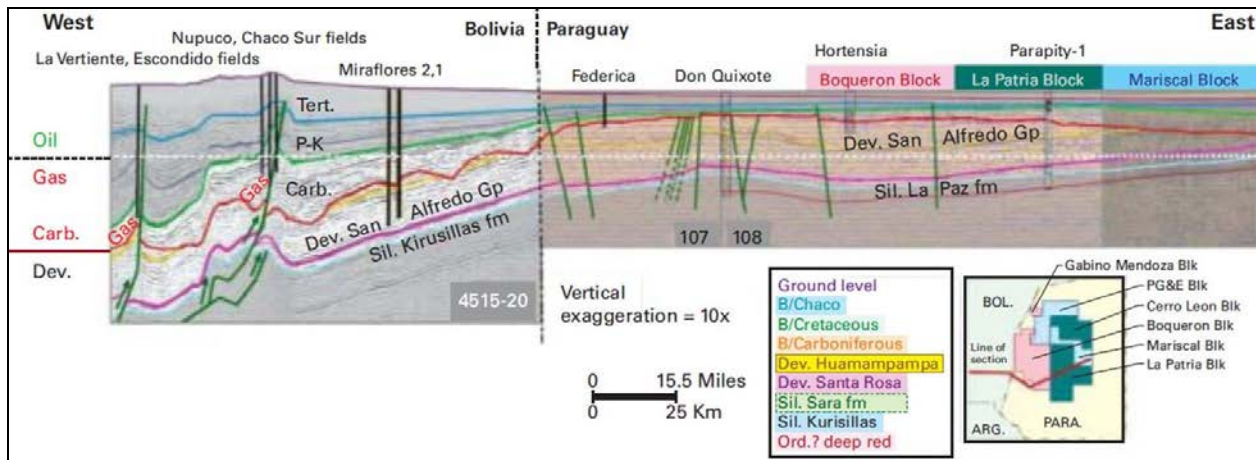
Figure VII-5: Prospective Area of the Devonian Los Monos Formation, Chaco Basin, Paraguay and Bolivia



The main source rocks include the Silurian Kirusillas Formation and the Devonian Los Monos and Icla formations.<sup>10</sup> The Devonian, considered the main source rock for the world-class conventional gas fields in the Tarija Basin foothills of southeast Bolivia, appears to have shale gas potential in northwest Paraguay where structure is considerably simpler, **Figure VII-6**. The gas window in this basin reportedly is at about 2 km depth.

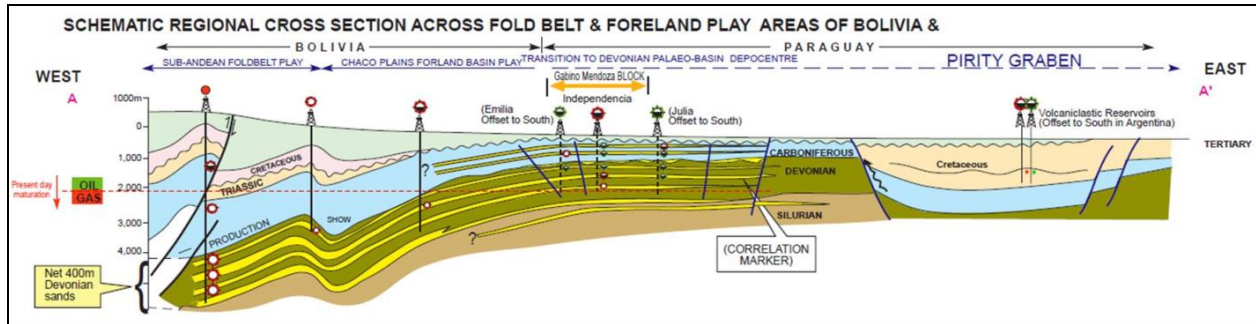
Significant shale gas potential exists within the 8,000- to 12,000-foot thick Devonian Los Monos Formation in the Carandaity and Curupaity sub-basins of Paraguay. The Devonian is exceptionally thick in southern Bolivia but consists mainly of coarse-grained sandstones there. The Devonian is also deeper and structurally more complex in much of Bolivia, **Figure VII-7**. Within the Los Monos, the San Alfredo Shales appear to be most prospective, comprising a lower sandy unit and an upper thick, monotonous black shale that formed under shallow marine conditions.<sup>11</sup> The thickest Devonian section (8,339 feet) penetrated in the Chaco Basin was in the Pure Oil Co. Mendoza-1 well. The Los Monos marine shale accounted for about 8,200 feet of this section.<sup>12</sup>

Figure VII-6: Regional Seismic Time Section Across the Chaco Basin of Bolivia and Paraguay, Showing Thick and Mostly Flat-Lying Silurian and Devonian Source Rocks.



Source: Wade, 2009

Figure VII-7: Regional Cross-Section Across the Chaco Basin of Bolivia and Paraguay, Showing Thick and Mostly Flat-Lying Silurian and Devonian Source Rocks.



Source: CDS Oil and Gas Group, PLC, 2006

Scarce geochemical data suggest 2.5% overall average TOC for the entire Los Monos, but richer zones are likely to be present within this thick and poorly documented unit. An exploration well in the Curupaity sub-basin measured up to 2.1% TOC in the Los Monos. Independent E&P Amerisur reports TOC of 1.44% to 1.86% in the Devonian Los Monos Fm in the Curupaity sub-basin.<sup>13</sup> Depth to the Los Monos Shale can exceed 10,000 feet (3,000 m) in deep synclines such as the San Pedro Trough.<sup>14,15</sup> Structural uplifts within the Chaco Basin have high geothermal gradients and are gas-prone.

Another potential source rock is the Puesto Guardian Member in the lower portion of the U. Cretaceous Yacoraite Formation. The Puesto Guardian reportedly contains about 78 m of black shale within a 6,000-km<sup>2</sup> area of the Piritu Sub-basin of the Cretaceous Basin.<sup>16</sup> TOC is up to 12%, consisting of Type II / III amorphous and algal kerogen that was deposited in

lacustrine to restricted marine environments. Peak hydrocarbon maturation and charge is estimated to have occurred 34-40 million years ago, with current maturity in the oil window. However, the potential of the Cretaceous shale was not assessed due to insufficient geologic control.

## 2.2 Reservoir Properties (Prospective Area)

The Devonian Los Monos Formation is exceptionally thick (as much as 12,000 feet) in the Chaco Basin, of which 2,000 feet (San Alfredo Shales) was conservatively assumed to be organic-rich. Faulting is not extensive, thus relatively little area is sterilized due to structural complexity.

The shale matrix reportedly consists primarily of brittle minerals such as calcite, dolomite, albite feldspar, ankerite, quartz as well as significant rutile and pyrite. Some clay is present -- mainly illite, kaolinite and chlorite – but is considered “less common.”<sup>17</sup> Temperature gradients range from elevated 1.9°F/100 feet on structural highs to 1.0°F/100 feet in the Carandaity sub-basin.

Depth and thermal maturity of the Devonian Los Monos Formation are relatively well constrained in the Paraguay portion of the Chaco Basin. The prospective area in Paraguay is estimated at 22,210 mi<sup>2</sup>, of which 6,200 mi<sup>2</sup> is in the oil window; 7,450 mi<sup>2</sup> is in the wet gas/condensate thermal maturity window; and 8,560 mi<sup>2</sup> is in the dry gas window. An additional 8,760 mi<sup>2</sup> is prospective in Bolivia, of which 670 mi<sup>2</sup> is in the oil window; 2,440 mi<sup>2</sup> is in the wet gas/condensate thermal maturity window; and 5,650 mi<sup>2</sup> is in the dry gas window.

## 2.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from the Devonian Los Monos black shale in the Paraguay portion of the Chaco Basin are estimated at 67 Tcf of shale gas and 3.2 billion barrels of shale oil and condensate, Tables VII-1 and VII-2. Bolivia has further estimated resources of 37 Tcf of shale gas and 0.6 billion barrels of shale oil and condensate. Risked shale gas and shale oil in-place are estimated at 457 Tcf of shale gas and 75 billion barrels of shale oil for the two countries. The play has moderate to high net resource concentrations of 28 to 141 Bcf/mi<sup>2</sup> for shale gas and 19 to 46 million bbl/mi<sup>2</sup> for shale oil, depending on thermal maturity window.

## 2.4 Recent Activity

Initial shale evaluation is occurring on existing conventional petroleum exploration leases in the Chaco Basin, but no shale-specific drilling or testing has occurred yet. President Energy PLC (UK) holds eight conventional petroleum exploration licenses which it considers to have shale gas/oil potential.

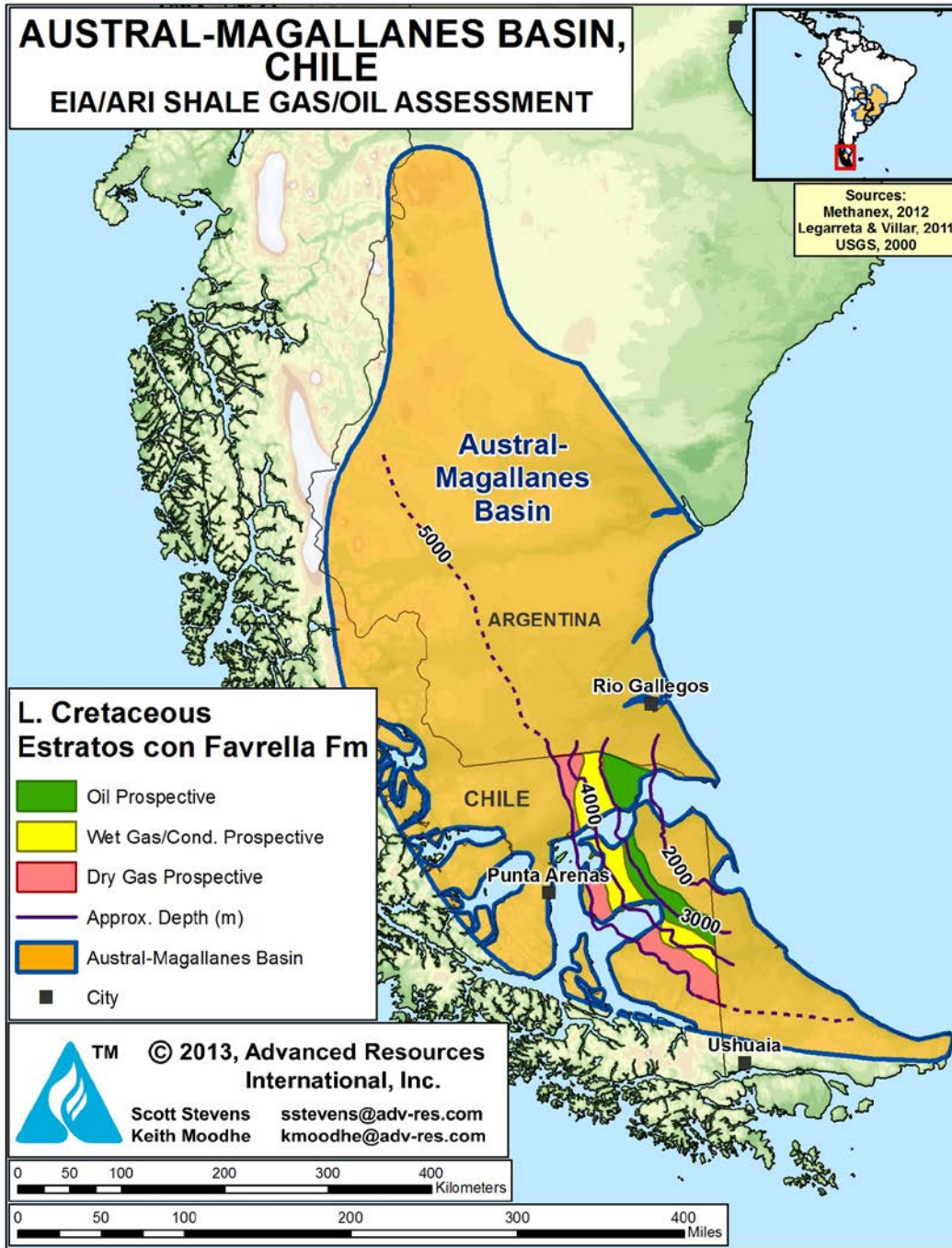
## 3 MAGALLANES BASIN (CHILE)

### 3.1 Introduction and Geologic Setting

Located in southern Patagonia, the 65,000-mi<sup>2</sup> Austral-Magallanes Basin has promising but untested shale gas potential, **Figure VII-8**. While most of the basin is in Argentina, where it is called the Austral Basin, a portion of the basin is located in Chile's Tierra del Fuego region, where it is referred to as the Magallanes Basin. The Chile portion of the basin, which started producing conventional natural gas over 60 years ago, currently accounts for most of that country's oil and gas output, produced primarily from deltaic to fluvial sandstones in the Early Cretaceous Springhill Formation at depths of about 6,000 feet.

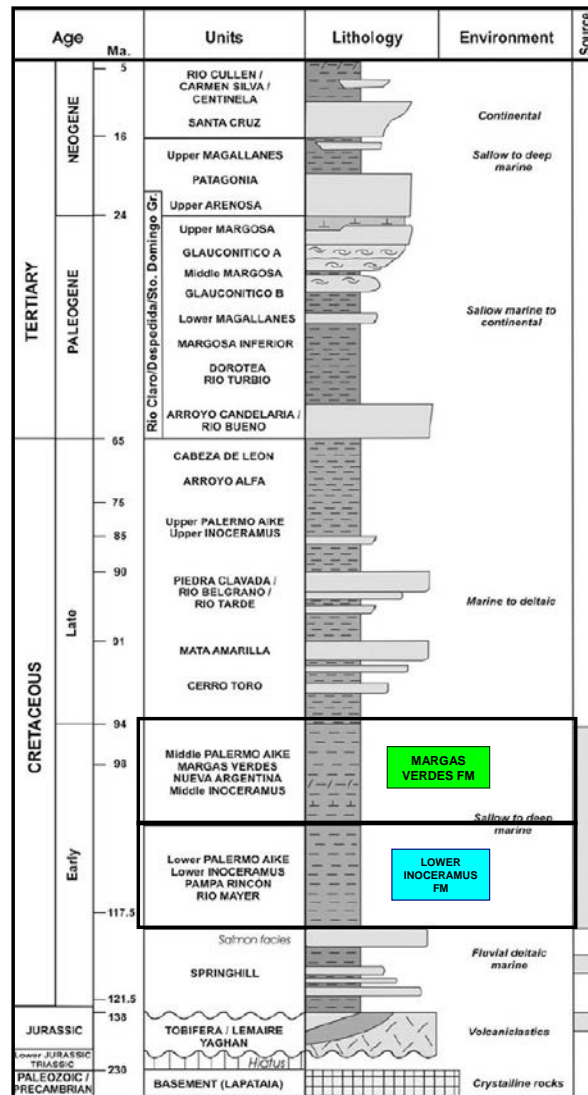
The Magallanes Basin comprises two main structural regions: a normal faulted eastern region and a thrust faulted western area. The basin contains a thick sequence of Upper Cretaceous and Tertiary sedimentary and volcanoclastic rocks which unconformably overlie deformed metamorphic basement of Paleozoic age. Total sediment thickness ranges from 3,000 to 6,000 feet along the eastern coast to a maximum 25,000 feet along the basin axis. Jurassic and Lower Cretaceous petroleum source rocks are present at moderate depths of 6,000 to 10,000 feet across large areas.<sup>18</sup> The overlying Cretaceous section comprises mainly deepwater turbidite clastic deposits up to 4 km thick, which appear to lack shale gas and oil potential.<sup>19</sup>

Figure VII-8: Prospective Area of the L. Cretaceous Estratos con Favrella Formation, Magallanes Basin, Chile



The organic-rich shales of Jurassic and Early Cretaceous age formed under anoxic marine conditions within a Neocomian sag on the edge of the Andes margin, Figure VII-9. The basal sequence consists of Jurassic source rocks that accumulated under restricted lacustrine conditions within small half-grabens. Interbedded shale and sandstone of the Zapata and Punta Barrosa formations were deposited in a shallow-water marine environment.<sup>20</sup> The mid-lower Jurassic Tobifera Formation contains 1% to 3% TOC (maximum 10% in coaly shales), consisting of Types I to III kerogen. However, this unit is mainly coaly and probably insufficiently brittle for shale exploration.

Figure VII-9: Stratigraphy of the Austral-Magallanes Basin, Argentina and Chile



Source: Rossello et al., 2008

Overlying the Tobifera Fm are more prospective shales within the Early Cretaceous Estratos con Favrella Formation (or Lower Inoceramus or Palermo Aike in Argentina), deposited under shallow water marine conditions. The Lower Inoceramus Formation is 50 to 400 m thick. In the Argentina portion of the basin, the total shale thickness (including the Magnas Verdes Formation) ranges from 800 feet thick in the north to 4,000 feet thick in the south, representing neritic facies deposited in a low-energy and anoxic environment.<sup>21</sup> Total organic content of these two main source rocks have been reported to range from 1.0% to 2.0%, with hydrogen index of 150 to 550 mg/g.<sup>22</sup> More recent analysis conducted by Chesapeake Energy of the Lower Cretaceous Estratos con Favrella Formation in Chile indicates this unit contains marine-deposited shale with consistently good to excellent (up to 6%) TOC, particularly near its base.<sup>23</sup>

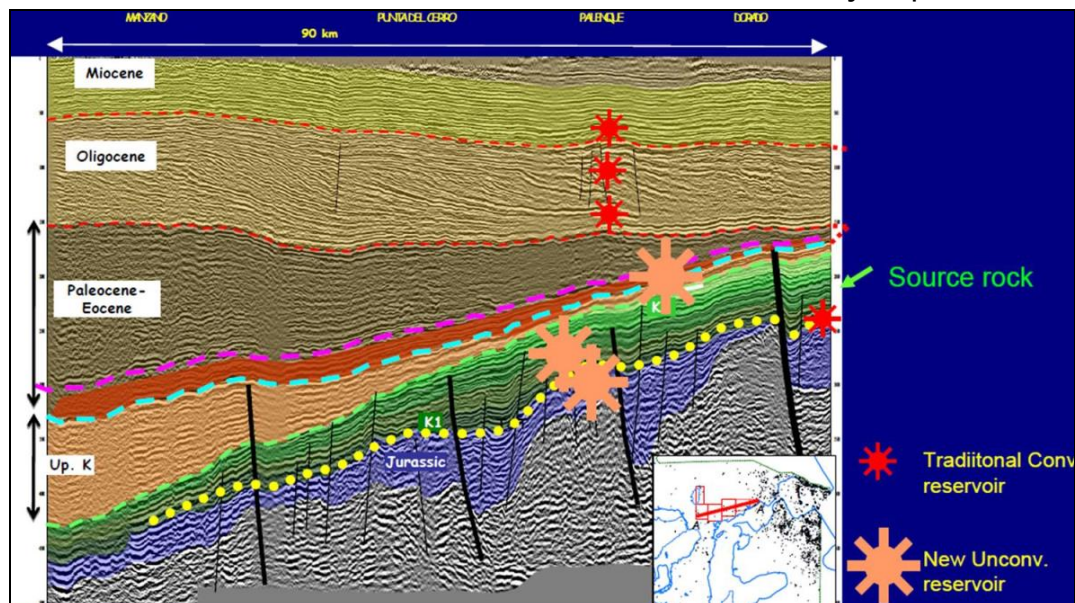
**Figure VII-10**, a seismic time section across the basin, shows the 180-m thick Estratos con Favrella Formation dipping gently west in a relatively simple structural setting. Net organic-rich shale thickness was estimated by ENAP to be only 40 to 120 ft, although this appears conservative and we assumed 280 net ft. ENAP also estimated porosity of 6% to 12%, but we assumed a more conservative estimate of 6%. Thermal maturity increases gradually with depth in a half-moon pattern, ranging from oil-prone ( $R_o$  0.8%) to dry gas prone ( $R_o$  2.0%). The transition from wet to dry gas ( $R_o$  1.3%) occurs at a depth of about 3,600 m in this basin.<sup>24</sup>

### 3.2 Reservoir Properties (Prospective Area)

Chile's portion of the Magallanes Basin has an estimated 5,000-mi<sup>2</sup> prospective area with organic-rich shale in the Estratos con Favrella and adjoining Lower Cretaceous formations. Of this total prospective area, about 1,580 mi<sup>2</sup> is in the oil window; 1,920 mi<sup>2</sup> is in the wet gas/condensate thermal maturity window; and 1,500 mi<sup>2</sup> is in the dry gas window. The Estratos con Favrella and adjoining shales average about 800 ft thick (organic-rich), 8,000 to 13,500 ft deep, and have estimated 3.5% average TOC. Thermal maturity ( $R_o$ ) ranges from 0.7% to 2.0% depending mainly on depth. Porosity is estimated at about 5%. The Estancia Los Lagunas gas condensate field in southeast Argentina measured a 0.46 psi/ft pressure gradient with elevated temperature gradients in the Serie Tobifera Fm, immediately underlying the Lower Inoceramus equivalent.<sup>25</sup>



Figure VII- 10: Seismic Time Section Across the Magallanes Basin, Showing Marine Source Rock Shales in the 180-m Thick L. Cretaceous Estratos con Favrella Formation within a Relatively Simple Structural Setting.



Source: Methanex, September 27, 2012

### 3.3 Resource Assessment

Risked, technically recoverable shale gas and oil resources from the Estratos con Favrella and adjoining Lower Cretaceous formations in the Chile portion of the Magallanes Basin are estimated at 48 Tcf of shale gas and 2.4 billion barrels of shale oil and condensate, Tables VII-1 and VII-2. Risked shale gas and shale oil in-place are estimated at 228 Tcf and 47 billion barrels, respectively. The play has moderate to high net resource concentrations of 33 to 156 Bcf/mi<sup>2</sup> for shale gas and 15 to 48 million bbl/mi<sup>2</sup> for shale oil, depending on thermal maturity window.

### 3.4 Recent Activity

No shale leasing or exploration activity has been reported in the Magallanes Basin. Methanex operates a methanol manufacturing plant in the basin which is running at about 10% of its 2 million t/year capacity due to local shortages of natural gas supply.<sup>26</sup> During 2011-2, Methanex had partnered with ENAP on conventional oil and gas exploration in the Magallanes Basin and also had expressed interest in shale gas exploration. However, recently the company decided to relocate about half of its methanol production capacity in Chile to Louisiana, USA.<sup>27</sup>

UK-based GeoPark holds conventional petroleum leases in the Magallanes Basin of Chile, which the company notes contains shales in the Estratos con Favrella Formation which previously have produced oil. In 2012 GeoPark conducted diagnostic fracture injection tests on eight wells on the Fell Block to determine reservoir properties of the shale.<sup>28</sup>

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