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Technically Recoverable Shale Oil and Shale Gas Resources:

Brazil

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Executive Summary

Introduction

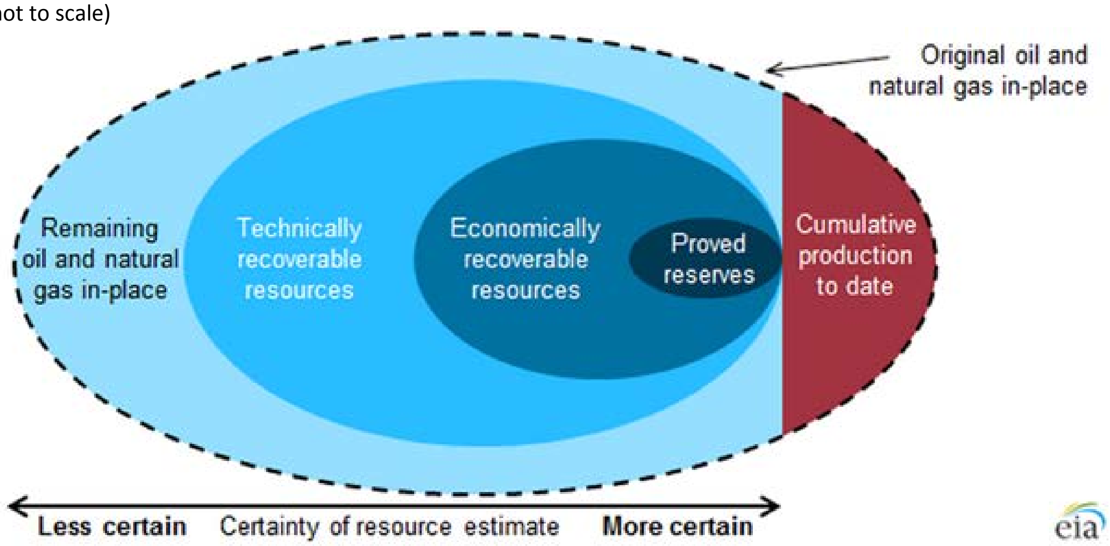
Although the shale resource estimates presented in this report will likely change over time as additional information becomes available, it is evident that shale resources that were until recently not included in technically recoverable resources constitute a substantial share of overall global technically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

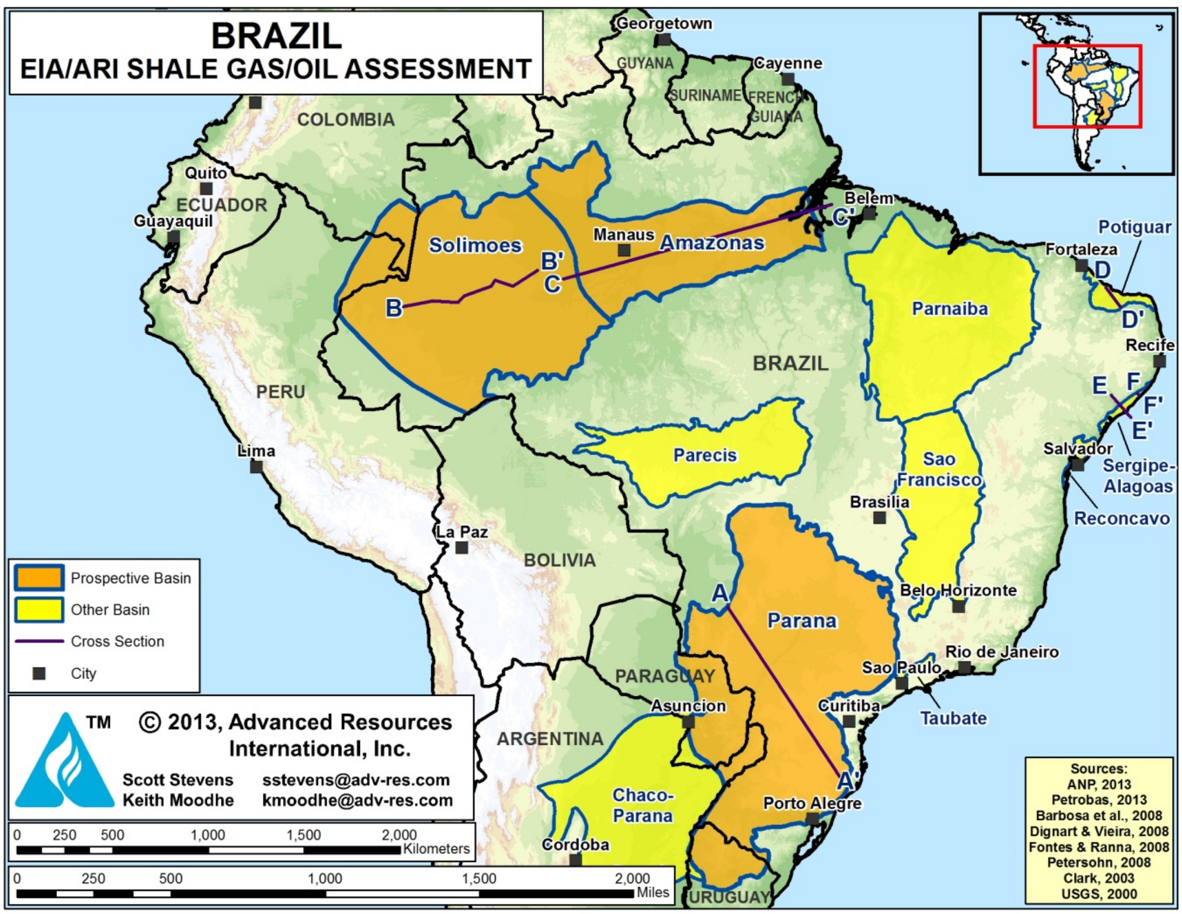
1. **Tight oil produced from low permeability sandstone and carbonate formations** that can often be found adjacent to shale oil formations. Assessing those formations was beyond the scope of this supplement as in the previous report.
2. **Coalbed methane and tight natural gas** and other natural gas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

VI. BRAZIL

SUMMARY

While Brazil's most prolific petroleum basins lie offshore, the country has 18 mostly undeveloped and lightly explored sedimentary basins onshore, **Figure VI-1**. Three of these basins -- the Paraná in the south and the Solimões and Amazonas in the north – produce significant conventional oil and gas from demonstrated source rock systems. These three basins also have sufficient geologic data to be assessed for shale gas and shale oil potential.

Figure VI-1: Prospective Shale Basins of Brazil



Source: ARI, 2013

The main shale target is the Devonian (Frasnian) marine black shale, which is extensively developed in the three structurally simple basins but has relatively modest TOC (2-2.5%). Several other basins in Brazil may have shale gas and oil potential but lack proven source rock systems, are thermally immature, and/or lack sufficient public data for assessment.

Brazil's risked, technically recoverable shale gas and shale oil resources in the Paraná, Solimões and Amazonas basins are estimated at 245 Tcf and 5.4 billion barrels, Tables VI-1 and VI-2. Risked, in-place shale resources are estimated to be 1,279 Tcf of shale gas and 134 billion barrels of shale oil. No shale-focused exploration leasing or drilling has been announced to date in Brazil.

Table VI-1. Shale Gas Reservoir Properties and Resources of Brazil

Basic Data	Basin/Gross Area		Parana (747,000 mi^2)			Solimoes (350,000 mi^2)		Amazonas (230,000 mi^2)		
	Shale Formation		Ponta Grossa			Jandiatuba		Barreirinha		
	Geologic Age		Devonian			Devonian		Devonian		
	Depositional Environment		Marine			Marine		Marine		
Physical Extent	Prospective Area (mi^2)		25,600	18,050	22,840	8,560	54,750	5,520	3,260	44,890
	Thickness (ft)	Organically Rich	1,000	1,000	1,000	160	160	260	300	300
		Net	300	300	300	120	120	195	225	225
	Depth (ft)	Interval	9,500 - 13,000	10,000 - 14,000	12,000 - 16,400	3,300 - 10,000	10,000 - 16,400	6,500 - 13,000	8,000 - 14,000	3,300 - 16,400
		Average	11,000	12,000	14,000	7,500	12,000	9,500	11,500	12,000
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.0%	2.2%	2.2%	2.5%	2.5%	2.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.50%	1.15%	1.60%	0.85%	1.15%	1.60%
	Clay Content		Low/Medium	Low/Medium	Low/Medium	Medium	Medium	Medium	Medium	Medium
Resource	Gas Phase		Assoc. Gas	Wet Gas	Dry Gas	Wet Gas	Dry Gas	Assoc. Gas	Wet Gas	Dry Gas
	GIP Concentration (Bcf/mi^2)		25.5	55.7	91.3	20.1	36.1	15.2	45.4	70.2
	Risked GIP (Tcf)		78.5	120.7	250.4	25.8	296.8	12.6	22.2	472.4
	Risked Recoverable (Tcf)		6.3	24.1	50.1	5.2	59.4	1.0	4.4	94.5

Table VI-2. Shale Oil Reservoir Properties and Resources of Brazil

Basic Data	Basin/Gross Area		Parana (747,000 mi^2)		Solimoes (350,000 mi^2)	Amazonas (230,000 mi^2)	
	Shale Formation		Ponta Grossa		Jandiatuba	Barreirinha	
	Geologic Age		Devonian		Devonian	Devonian	
	Depositional Environment		Marine		Marine	Marine	
Physical Extent	Prospective Area (mi^2)		25,600	18,050	8,560	5,520	3,260
	Thickness (ft)	Organically Rich	1,000	1,000	160	260	300
		Net	300	300	120	195	225
	Depth (ft)	Interval	9,500 - 13,000	10,000 - 14,000	3,300 - 10,000	6,500 - 13,000	8,000 - 14,000
		Average	11,000	12,000	7,500	9,500	11,500
Reservoir Properties	Reservoir Pressure		Normal	Normal	Normal	Normal	Normal
	Average TOC (wt. %)		2.0%	2.0%	2.2%	2.5%	2.5%
	Thermal Maturity (% Ro)		0.85%	1.15%	1.15%	0.85%	1.15%
	Clay Content		Low/Medium	Low/Medium	Medium	Medium	Medium
Resource	Oil Phase		Oil	Condensate	Condensate	Oil	Condensate
	OIP Concentration (MMbbl/mi^2)		26.8	11.4	5.5	18.3	8.7
	Risked OIP (B bbl)		82.4	24.7	7.1	15.1	4.3
	Risked Recoverable (B bbl)		3.30	0.99	0.28	0.61	0.17

INTRODUCTION AND GEOLOGIC OVERVIEW

Brazil has 18 onshore sedimentary basins, of which 14 basins may have petroleum source rocks. However, since the 1980s Brazil has focused mainly on its offshore oil and gas resources, while the onshore basins have seen less activity. Only two onshore basins have significant oil and gas output (Amazonas and Paraná). Relatively few conventional oil and gas wells have been drilled to the deep source rock intervals in these basins. Shale exploration drilling has not yet occurred. As a result, geologic data on the shale source rocks in Brazil are relatively scant.

Brazil's National Oil and Gas Agency (ANP) has conducted exploration surveys, mostly gravity and magnetics with minimal drilling, on four onshore basins: the Amazonas, Parana, Parnaiba, and part of the Sao Francisco.[1] Recently ANP estimated that Brazil may have 208 Tcf of shale gas resources, based on a rough analogy of three onshore Brazilian basins (Parnaiba, Parecis, Recôncavo) with the Barnett Shale in the Fort Worth Basin of Texas.[2] Petrobras, the national oil company, recently drilled its first shale oil well in Argentina but has not announced plans for shale drilling in Brazil.

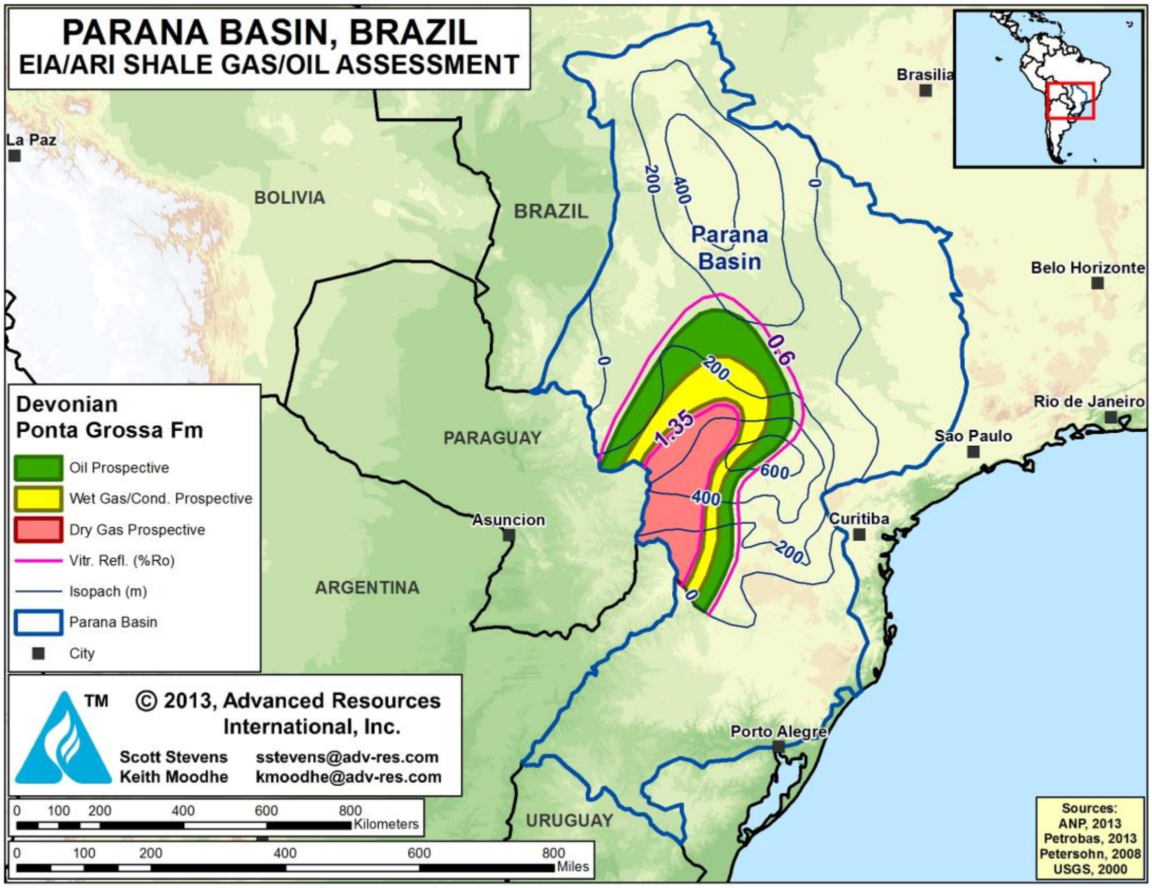
EIA/ARI has assessed the shale resource potential of three of Brazil's onshore basins (Paraná, Solimões, and Amazonas). These basins have prospective shales that sourced commercially productive conventional oil and gas fields as well as sufficient available geologic data for resource analysis. In addition, Brazil has a half-dozen other basins which may have shale potential, but their source rock systems are less proven and/or they lack sufficient available geologic data. These six other basins -- which were reviewed but not formally assessed in this study -- include the Potiguar, Parnaiba, Parecis, Recôncavo, Sergipe-Alagoas, Sao Francisco, Taubaté, and Chaco- Paraná.

1. PARANÁ BASIN

1.1 Introduction and Geologic Setting

Located in Brazil's economically most developed southern region, the Paraná Basin is a large (1.5 million km^2) depositional feature that covers 747,000 mi^2 within Brazil, with additional area in Paraguay, Uruguay, and northern Argentina, **Figure VI-2**. Major infrastructure in the region includes the Brazil-Bolivia and Uruguaiana-Porto Alegre pipelines.

Figure VI-2: Prospective Shale Gas and Shale Oil Areas in the Paraná Basin



Source: ARI, 2013

Conventional petroleum exploration began in the Paraná Basin during the 1890's, but the first (and thus far only) commercial discovery came in 1996, with the low-permeability Barra Bonita gas field of limited output (36 Bcf total through 2009).[3] Approximately 124 petroleum wells have been drilled in the Brazil portion of the Paraná Basin, a low drilling density of 1 well per 10,000 km^2. In addition, some 30,000 km of 2D seismic have been acquired.[4] Only a fraction of this data set has been published and made available for our study.

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.[5] On the north the basin onlaps Precambrian basement. Some two-thirds of the basin is covered by flood basalts, partly obscuring the underlying geology from seismic and increasing the cost of drilling.

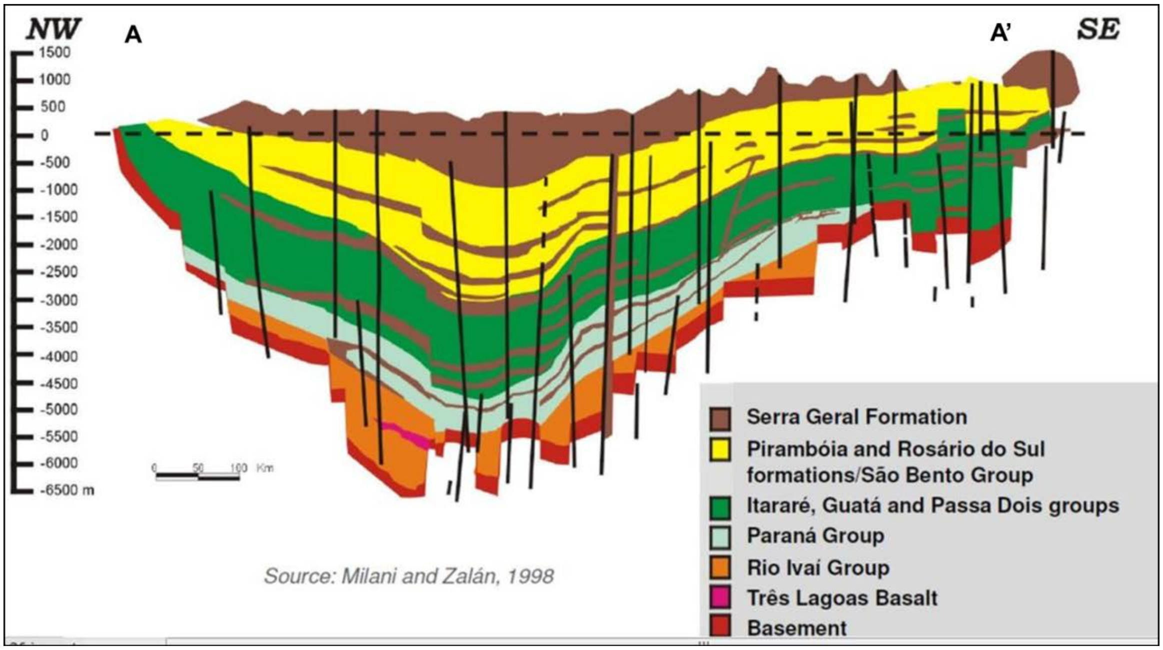
The structure of the Paraná Basin appears to be moderately simple, at least based on available data, consisting of a gentle syncline with minor faulting and secondary folding, **Figure VI-3**. Faults, predominately normal in orientation, are controlled by older basement faults (aulocogens) which separate large undeformed tracts of the basin interior. However, numerous igneous sills and dikes, related to emplacement of the flood basalts during the Early Cretaceous, intrude the sedimentary sequence. More detailed seismic reveals the presence of numerous smaller faults, **Figures VI-4 and VI-5**.

The main petroleum source rock in the Paraná Basin is the Devonian black shale of the Ponta Grossa Formation (Emsian/Frasnian), **Figure VI-6**. This 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 of the Late Carboniferous to Early Permian Itararé Group.[6]

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 basin area.

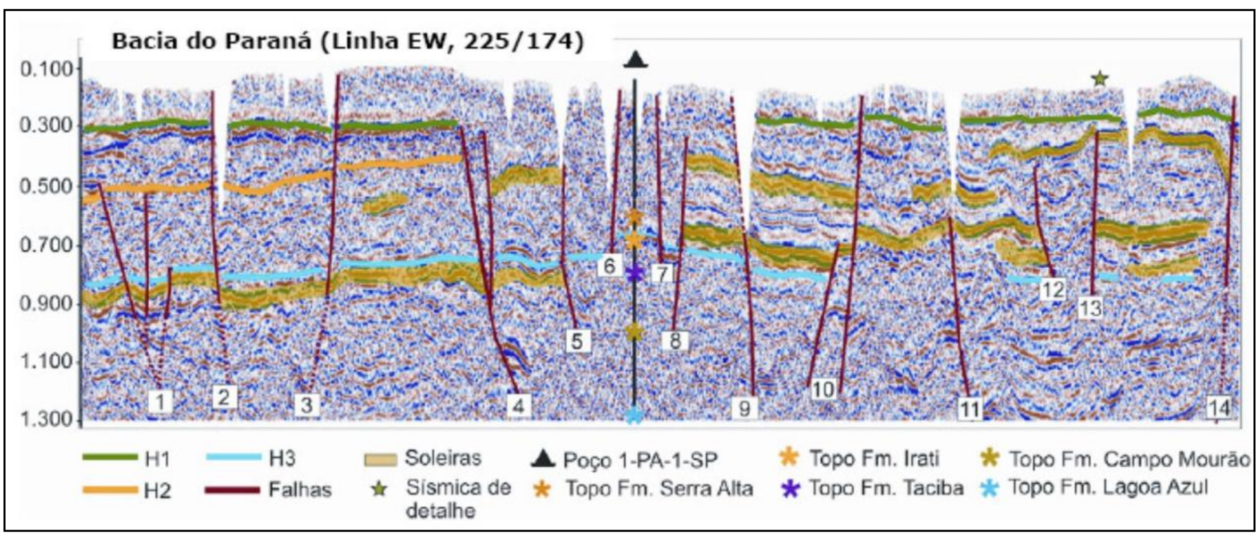
A second less prolific source rock in the Paraná Basin is the Permo-Triassic Irati Formation. This non-marine bituminous unit sourced oil trapped in biodegraded conventional sandstones (tar sands) of the Permian and Triassic Rio Bonito and Pirambóia formations.[7] The Irati Formation is widespread and can be organic-rich, averaging 8-13% TOC of Type I kerogen with peaks to 24%, but the shales are quite thin and thermally immature (R_o <0.5%). Petrobras is mining Irati oil shale from the surface at São Mateus do Sul and processing it using rock pyrolysis. Although the Irati Fm may be thermally mature in the deep Paraguay portion of the Paraná Basin,[8] its Brazil extension was not assessed due to low thermal maturity.

Figure VI-3. Cross-Section of the Paraná Basin, Brazil



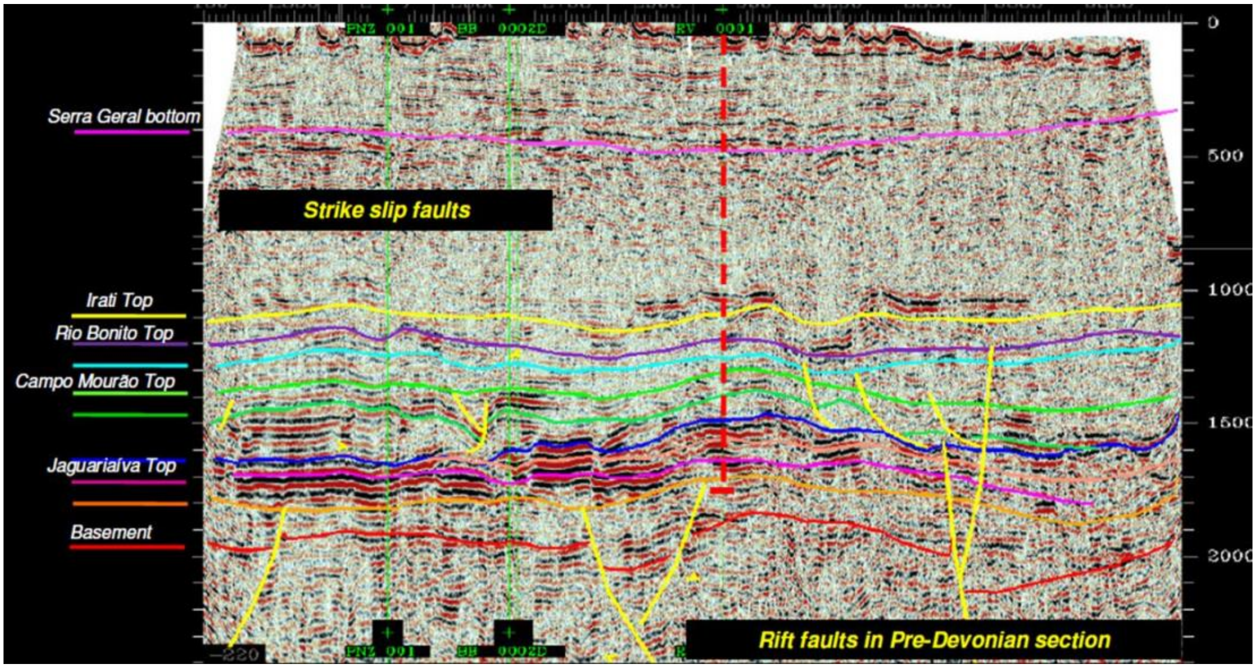
Source: ANP, 2012

Figure VI-4: Seismic Time Section Showing Regional Moderate Block Faulting of the Paraná Basin, Brazil



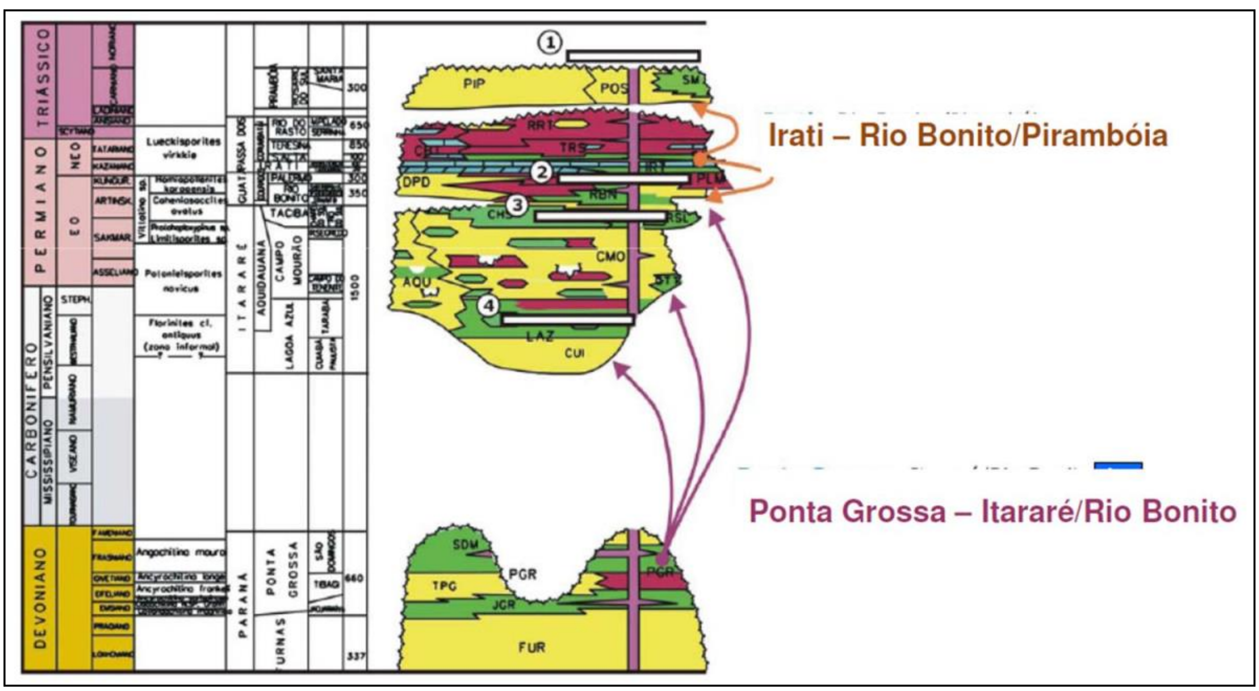
Source: Petersohn, 2003

Figure VI-5: Seismic Time Section of the Paraná Basin Showing Small Faults.



Source: Petersohn, 2003

Figure VI-6: Stratigraphy of Paraná Basin Showing Source Rock Shales, Devonian Ponta Grossa Formation



Source: Petersohn, 2003

1.2 Reservoir Properties (Prospective Area)

The prospective area of organic-rich shale in the Devonian Ponta Grossa Formation of the Paraná Basin is estimated at approximately 66,500 mi^2, of which 25,600 mi^2 is in the oil window; 18,050 mi^2 is in the wet gas/condensate thermal maturity window; and 22,840 mi^2 is in the dry gas window. The Devonian shale averages about 300 m thick (net), 11,000 to 14,000 ft deep, and has estimated 2.0% average TOC. Thermal maturity (R_o) ranges from 0.85% to 1.5% depending mainly on depth. 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 shale oil resources from Devonian Ponta Grossa (Frasnian) black shale in the Paraná Basin are estimated at 81 Tcf of shale gas and 4.3 billion barrels of shale oil and condensate, Tables VI-1 and VI-2. Risked shale gas and shale oil in-place is estimated at 450 Tcf and 107 billion barrels. The play has moderate net resource concentrations of 26 to 91 Bcf/mi^2 for shale gas and 11 to 27 million bbl/mi^2 for shale oil depending on thermal maturity window.

1.4 Recent Activity

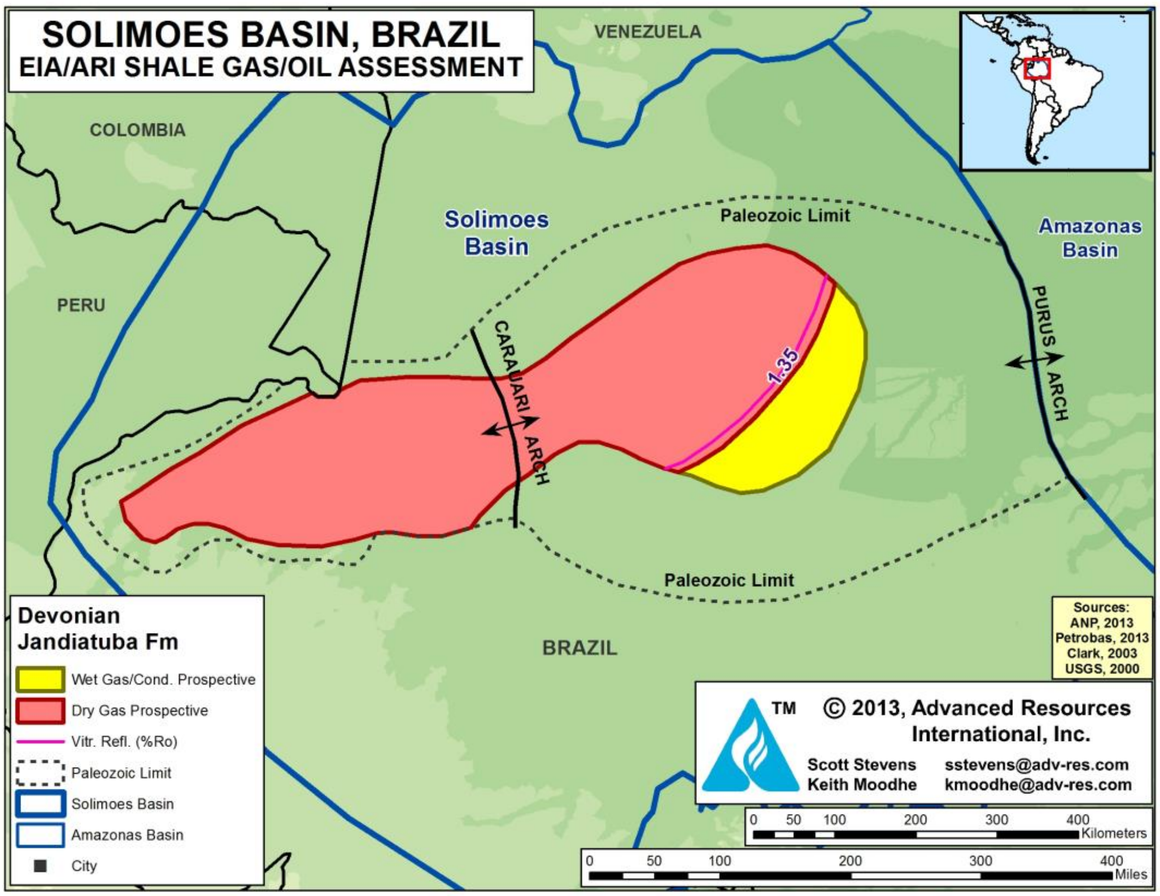
No shale gas/oil exploration activity has been reported in the Brazil portion of the Paraná Basin, although Amerisur Energy has discussed the shale potential of the Cretaceous Irati Fm in the Paraguay portion of the basin.

2. SOLIMÕES BASIN

2.1 Introduction and Geologic Setting

Located in northern Brazil, the Solimões Basin extends over 350,000 mi^2 of Amazon jungle, **Figure VI-7**. While less prolific than Brazil's offshore fields, the Solimões is the country's most productive onshore basin, with output of about 50,000 bbl/d of oil and 12 million m^3/d of natural gas from the Carboniferous Juruá Formation sandstone.[9]

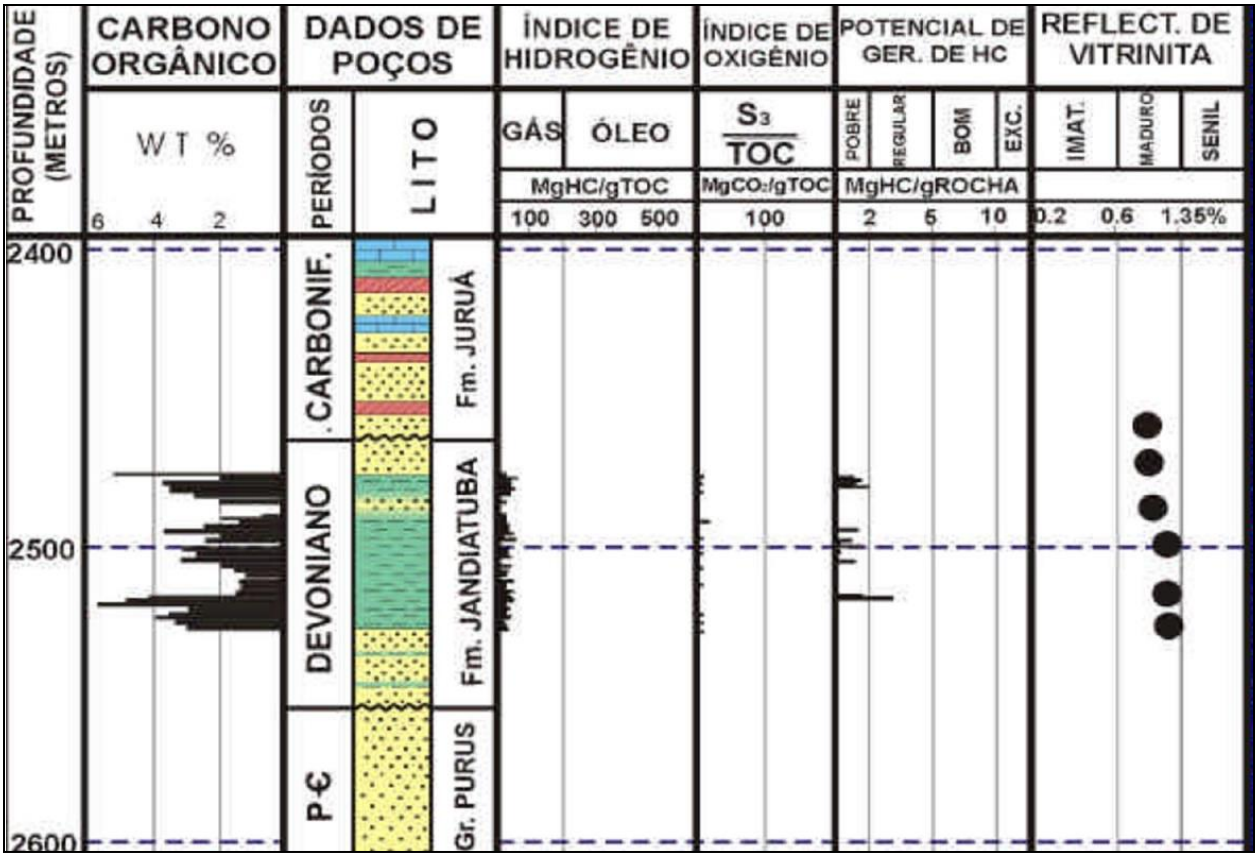
Figure VI-7: Prospective Shale Gas and Shale Oil Areas in the Solimões Basin



Source: ARI, 2013

These conventional reservoirs directly overlie and were sourced by marine-deposited source rocks within the Devonian Jandiatuba (mostly), Jaraqui and Ueré formations. The Jandiatuba Fm (Frasnian) contains a 50-m thick section of radioactive ("hot") black shale, with TOC ranging from 1% to 4% (average 2.2%; maximum 8.25%), **Figure VI-8**. Thermal maturity is mostly in the dry gas window (R_o >1.35%), apart from a small area in the east that is wet-gas prone (R_o 1.0% to 1.3%).[10]

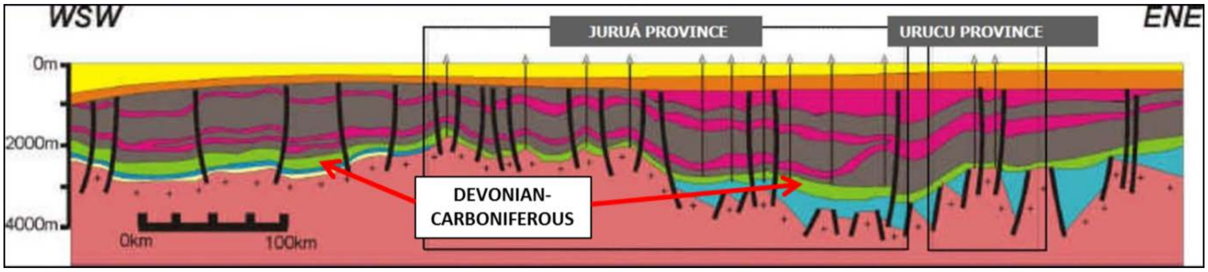
Figure VI-8: Black Shale in the Devonian Jandiatuba Formation of the Solimões Basin is about 40 m Thick with 1% to 4% TOC at this Location



Source: Clark, 2003

Figure VI-9, a regional cross-section oriented in the basin's strike direction, shows the mostly flat-lying but still moderately faulted Devonian shale at depths of 2 to 3 km. Note that a dip-oriented cross-section would reveal the steeper dips. Structural uplifts define several sub-basins. The easternmost Juruá Sub-basin, with up to 3.8 km of sedimentary rocks, accounts for most of the conventional oil and gas found in the Solimões Basin, indeed in the entire Paleozoic sequence of South America. The shale's thermal history is controlled more by proximity to igneous intrusions rather than simple burial depth.

Figure VI-9: Cross-Section (Strike Direction) of the Solimões Basin, Showing Flat-lying but Moderately Faulted Devonian Shale (Green) at Depths of 2 to 3 km.



Source: Clark, 2003

2.2 Reservoir Properties (Prospective Area)

The total estimated prospective area of organic-rich shale in the Devonian Jandiatuba Formation of the Solimões Basin is estimated at 63,000 mi^2, of which 8,560 mi^2 is in the wet gas thermal maturity window and 54,750 mi^2 is in the dry gas window. The Jandiatuba shale averages about 120 ft thick (net), 7,500 to 12,000 ft deep, and has estimated 2.2% average TOC. Porosity is estimated at 4% and the pressure gradient is assumed to be hydrostatic.

2.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from Devonian Jandiatuba black shale in the Solimões Basin are estimated at 65 Tcf of shale gas and 0.3 billion barrels of shale oil, out of risked shale gas and shale oil in-place of 323 Tcf and 7.1 billion barrels, Tables VI-1 and VI-2. The play has a moderate net resource concentration of 20 to 36 Bcf/mi^2 for shale gas and 5.5 million bbl/mi^2 for shale oil.

2.4 Recent Activity

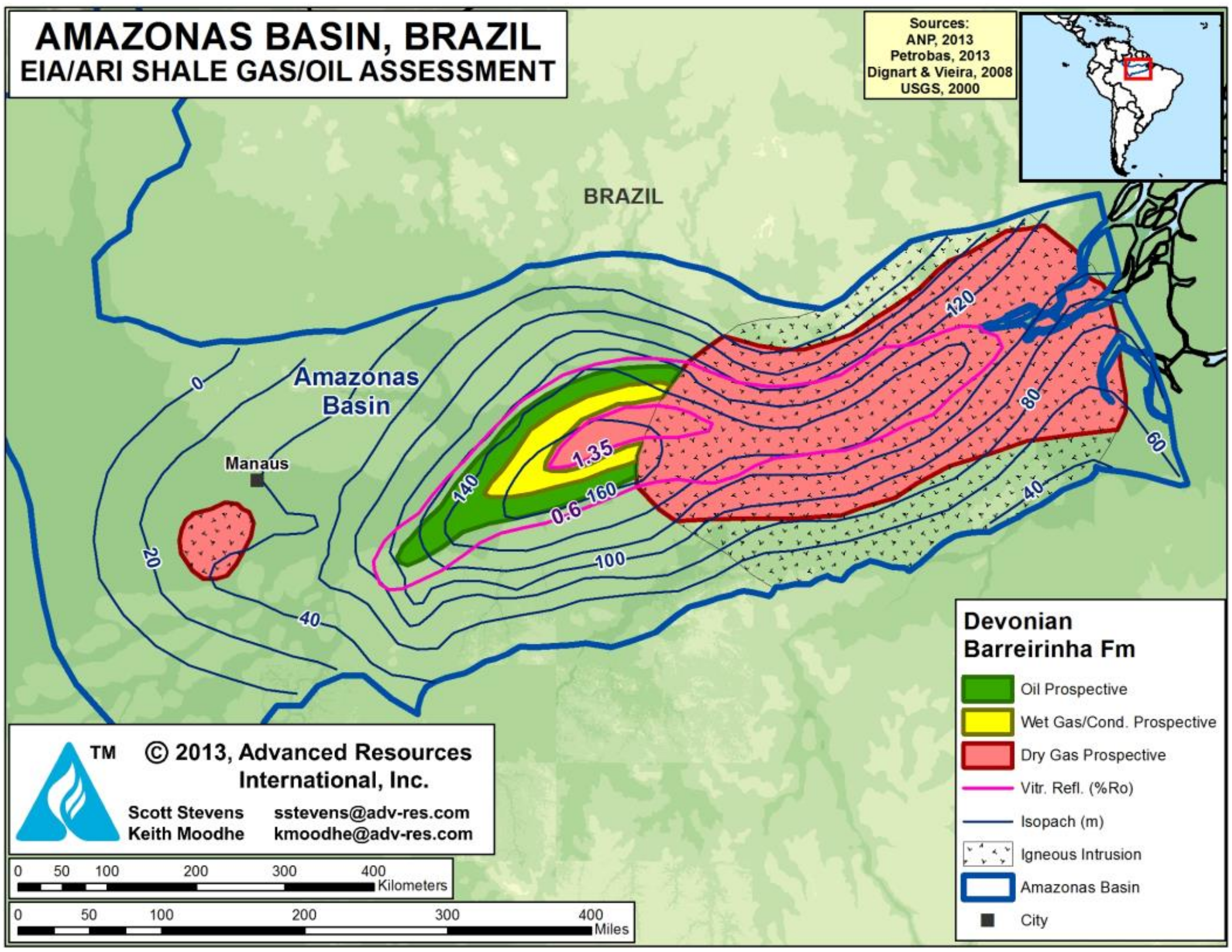
No shale gas/oil exploration activity has been reported in the Solimões Basin.

3. AMAZONAS BASIN

3.1 Introduction and Geologic Setting

Extending over more than 230,000 mi^2 of Amazon forest in remote northern Brazil, the Amazonas Basin is an ENE-WSW trending structural trough bounded by the Purus and Garupa arches, **Figure VI-10**. The first conventional petroleum fields were discovered in 1999 and commercialized starting in 2009, when the Urucu-Coari-Manaus gas and LPG pipeline system was commissioned. By late 2010, this pipeline was transporting about 0.2 Bcfd, mainly from the nearby Solimões Basin, along with smaller volumes from the Amazonas Basin.

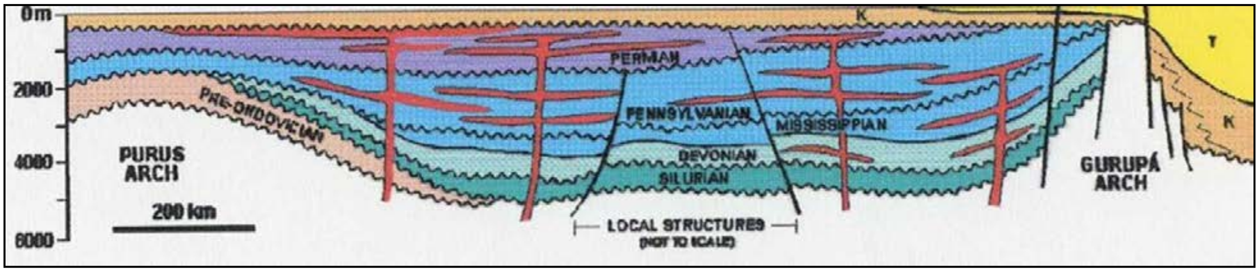
Figure VI-10: Prospective Shale Gas and Shale Oil Areas in the Amazonas Basin



Source: ARI, 2013

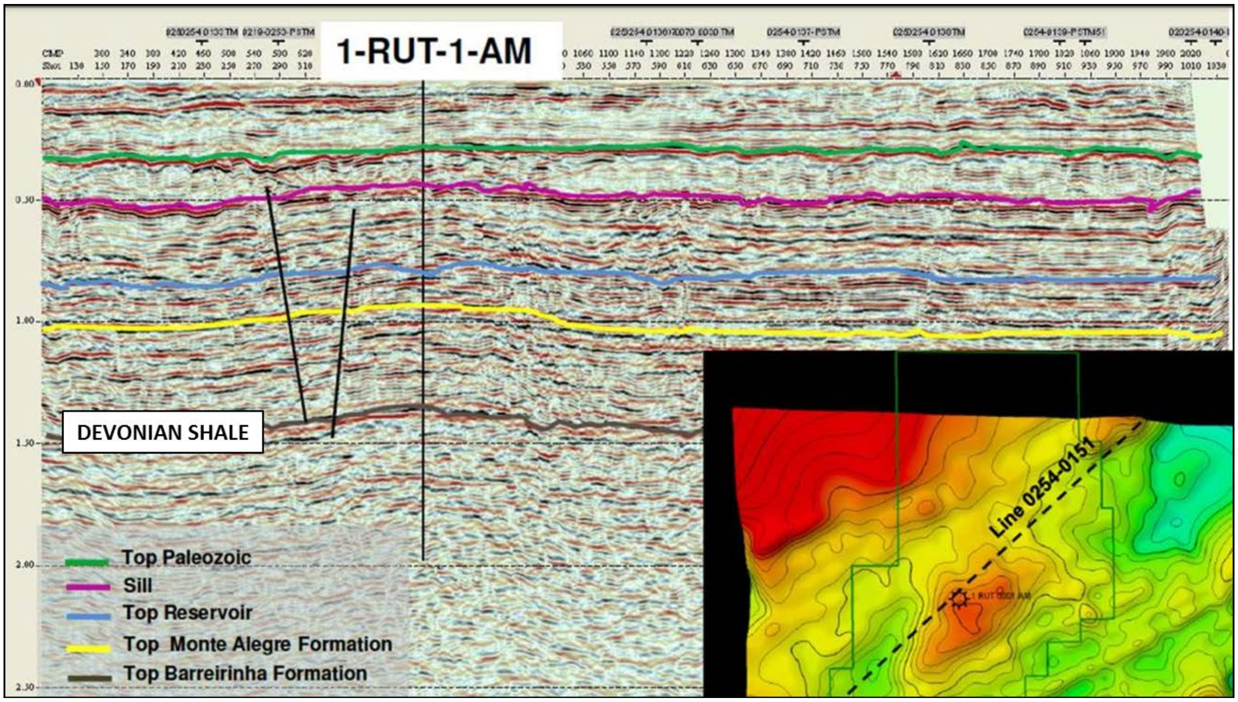
The Amazonas Basin contains up to 5 km of mostly Paleozoic sedimentary rock that are covered by Mesozoic and Cenozoic strata, **Figure VI-11**. While not structurally complex, the Amazonas Basin was extensively intruded by igneous activity during the Early Jurassic, particularly in the eastern half of the basin. This was followed by Cenozoic structural deformation that included extensional block and strike-slip faulting and salt tectonics. **Figure VI-12** illustrates the relatively simple local structure in one portion of the basin.

Figure VI-11: Devonian (Frasnian) Marine Black Shale Ranges from 2 to 4 Km Deep in the Amazonas Basin. Faults Appear to be Widely Spaced but Igneous Intrusions are Common.



Source: Dignart and Vieira, 2007

Figure VI-12: Seismic Time Section in the Amazonas Basin Showing Simple Structure of the Devonian Marine Black Shale.



Source: Dignart and Vieira, 2007

The petroleum system in the Amazonas Basin is broadly similar to that in the Solimões Basin. Up to 160 m (average 80 m) of laminated marine-deposited black shales are present in the Devonian Barreirinha Formation (Frasnian), which was the source rock for conventional sandstones of the overlying Nova Olinda Formation.[11] Ranging from 2 to 4 km deep, the Devonian shale has 2% to 5% TOC that consists of Type II kerogen. The Devonian is thermally immature (R_o < 0.5%) in the shallow and western portions of the basin, increasing to wet gas prone in the deeper center and dry gas prone in the more heavily intruded east. Additional marine black shales occur in the Silurian Pitinga Formation, but these contain less than 2% TOC and thus were not assessed.

3.2 Reservoir Properties (Prospective Area)

Based on the limited geologic control available for the Amazonas Basin, the total estimated prospective area of organic-rich shale in the Devonian Barreirinha Formation is estimated at about 54,000 mi^2, of which 5,520 mi^2 is in the oil window; 3,260 mi^2 is in the wet gas and condensate window; and 44,890 mi^2 is in the dry gas window. The Devonian shale averages 195-225 ft thick (net), 9,500-12,000 ft deep, and has estimated 2.5% average TOC. Porosity is estimated at 4% and the pressure gradient is assumed to be hydrostatic.

3.3 Resource Assessment

Risked, technically recoverable shale gas and shale oil resources from the Devonian Barreirinha Formation (Frasnian) black shale in the Amazonas Basin are estimated at 100 Tcf of shale gas and 0.8 billion barrels of shale oil and condensate, out of risked shale gas and shale oil in-place of 507 Tcf and 19 billion barrels, Tables VI-1 and VI-2. The play has a moderate net resource concentrations of approximately 15 to 70 Bcf/mi^2 for shale gas and 9 to 18 million bbl/mi^2 for shale oil.

3.4 Recent Activity

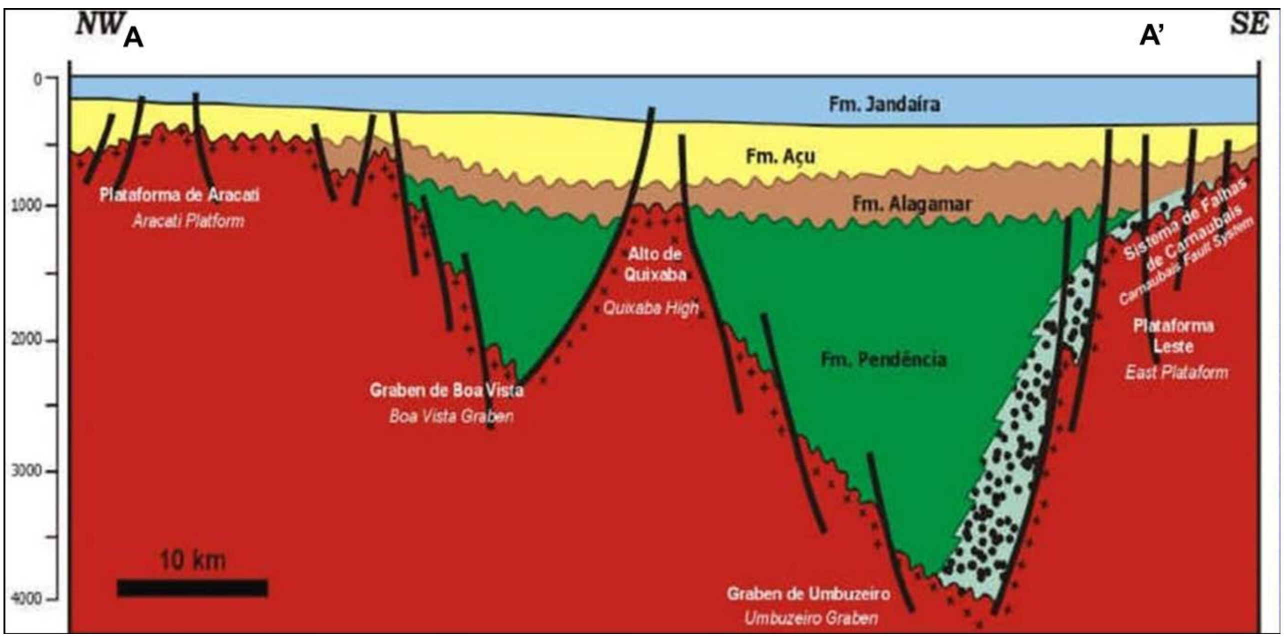
No shale gas/oil exploration leasing or drilling activity has been reported in the Amazonas Basin.

4. OTHER BASINS

More than a dozen other sedimentary basins occur in onshore Brazil. Most have no commercial oil and gas production and some lack identified petroleum generation and maturation systems. Some of these basins may have shale potential but public data are not currently sufficient for detailed characterization and assessment by EIA/ARI. However, these basins could be prospective for shale exploration and should be assessed once additional geologic data become available. Six of the more promising basins include:

- **Potiguar Basin.** This Neocomian rift basin in northeastern Brazil extends over an onshore area of about 33,000 km^2 plus a much larger area offshore. The onshore portion of the basin contains up to 4 km of mostly Cretaceous deposits. The basin comprises a number of smaller fault blocks, with major structures trending northeast-southwest, **Figure VI-13**. Oil production currently averages 125,000 bbl/day, making the Potiguar Basin Brazil's second largest production area after the offshore Campos Basin. The 5,000 mostly onshore wells have recovered a total of 0.5 billion barrels of oil and 0.5 Tcf of natural gas.[12]

Figure VI-13: Cross-Section of the Potiguar Basin, Showing the Pendência and Alagamar Formations.



Source: ANP, 2003

The Upper Cretaceous (Barremenian) to Paleocene Pendência Formation, a rift sequence, is considered the main petroleum source rock in the Potiguar Basin, containing about 4% TOC of Type I kerogen. The Alagamar Formation contains up to 6% TOC of Types I and II kerogen, but is shallow (<1 km) in the onshore.[13] However, shale resources were not assessed in the Potiguar Basin due to its apparent structural complexity and the lack of available data control on source rock depth, thickness, and thermal maturity.

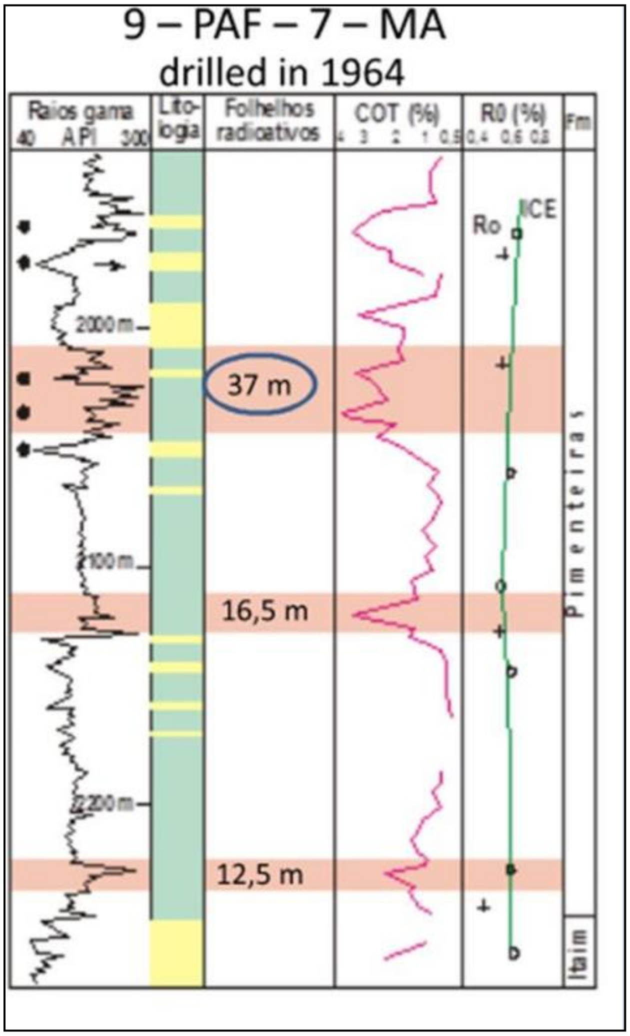
- **Parnaiba Basin.** Also located in northeastern Brazil, this large (600,000-km^2) circular basin contains up to 3.5 km of sedimentary rocks within a relatively simple -- albeit heavily intruded -- structural setting. The Devonian Pimenteiras Formation contains marine black shale up to 300 m thick with 2.0-2.5% TOC. Local independent operator MPX Energia S.A. has reported the company logged gas shows while drilling through a 23-m thick "naturally fractured" Devonian shale interval.[14]

  Figure VI-14 shows the distribution of thickness, depth, TOC, and thermal maturity of the Pimenteiras at a conventional exploration well in an undisclosed portion of the basin. Organic-rich shale in this well totals about 50 m thick at a depth of 2,000 to 2,200 m. The TOC ranges up to 4%, averaging 2.5%, but is thermally immature (R_o ~0.5%) at this location. ANP has projected that thermal maturity reaches oil- and eventually gas-prone levels in the deeper parts of the basin (1,600 to 2,500 m), and estimated 64 Tcf of recoverable shale gas resources, based on analogy with the Barnett Shale play in the Fort Worth Basin.[15]

  However, as just noted available data suggests the Pimenteiras Fm is thermally immature (R_o 0.5%) at a depth of 2,200 m and may only just be entering the oil window at 2,500 m. Other researchers have reported this unit to be thermally immature, apart from local contact zones near the abundant igneous intrusions. Note also that the basin lacks commercial oil and gas production. Given the sparse data available for this study, EIA/ARI did not assess the shale potential of the Parnaiba Basin.

- **Parecis Basin.** A frontier non-productive sedimentary basin in northern Brazil. ANP has noted that radioactive dark shale averages some 50 m thick in the deep basin grabens. As much as 106 m was logged at a depth of 4 km in one conventional petroleum well. ANP recently estimated that 124 Tcf of shale gas may be recoverable based on the Barnett Shale comparison. However, data available to EIA/ARI were not sufficient for assessing the shale potential of the Parecis Basin, which does not produce oil and gas.

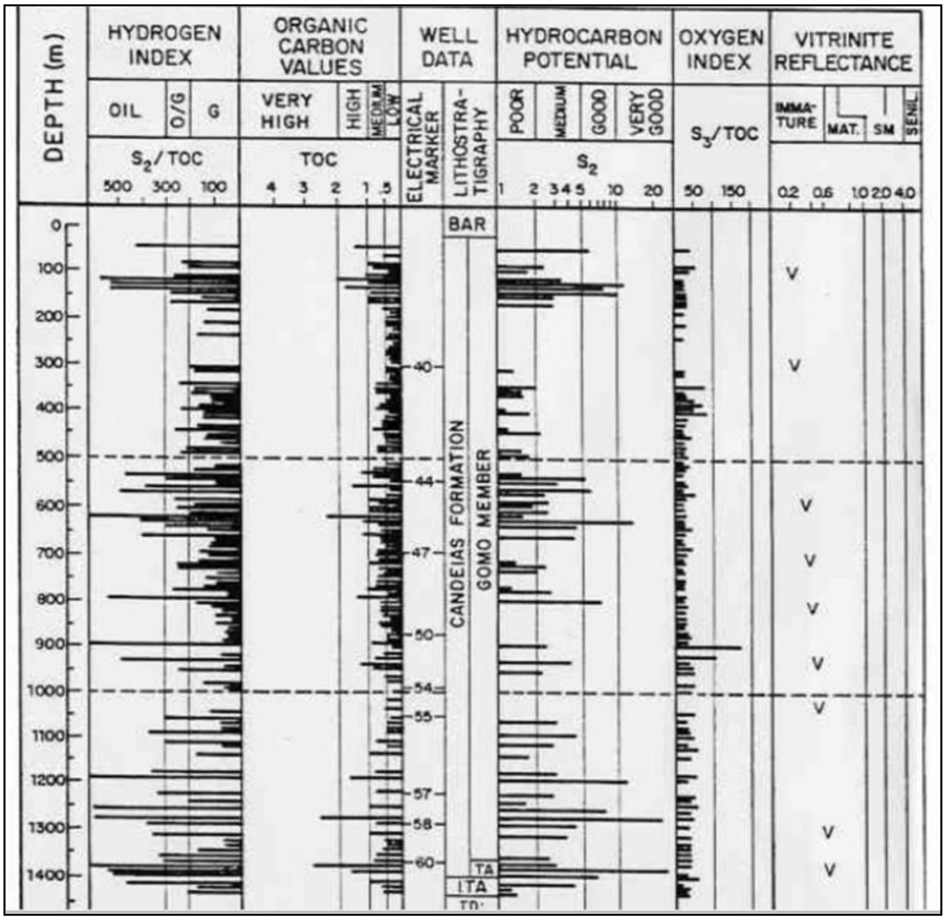
Figure VI-14: Source Rock Thickness, Depth, TOC, and Thermal Maturity of the Pimienta Shale in the Parnaiba Basin



Source: ANP, 2003

- **Recôncavo Basin.** One of many failed rift basins in eastern Brazil, the Recôncavo Basin was the country's first productive petroleum basin. Over 6,000 wells have drilled, of which some 1,800 extent producing wells make 50,000 bbl/day of oil. The Gomo Member of the Lower Cretaceous Candeias Formation, deposited in a lacustrine environment during early rifting, is considered the main source rock.[16] Although quite thick (200-1,000 m), the Gomo Member has relatively low TOC, mostly ranging from 1% to 2%, **Figure VI-15**. ANP recently estimated recoverable shale gas resources in the Recôncavo Basin to be 20 Tcf. However, based on EIA/ARI's screening criteria, the Gomo Member appears to be below the 2% average TOC cutoff and its shale potential was not assessed.

Figure VI-15: The Gomo Member of the Lower Cretaceous Candeias Formation in the Recôncavo Basin can be Thick (>1 km) but is Low in TOC (<2%) and Mostly Thermally Immature (R_o < 0.6%)



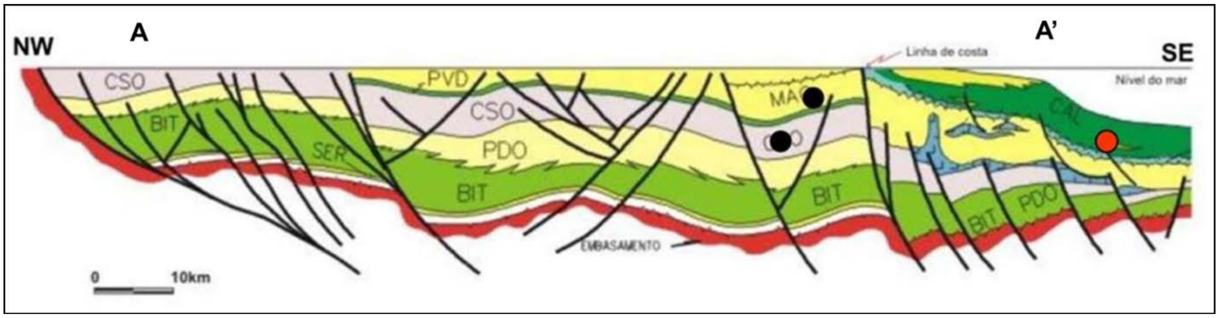
Source: ANP, 2003

- **Sergipe-Alagoas Basin.** Another Neocomian rift basin in northeastern Brazil, the Sergipe-Alagoas Basin extends over an onshore area of 12,600 km^2 as well as a considerably larger area offshore. The basin comprises a number of relatively small, isolated and tilted fault blocks, with major structures trending northeast-southwest, **Figure VI-16**.[17] To date some 57 conventional oil and gas fields have been discovered in the basin, with nearly 5,000 wells drilled, primarily in the onshore portion of the basin. **Figure VI-17** shows a detailed cross-section of the Campo de Pilar Field, showing the numerous closely spaced faults.

The Cretaceous Maceió Formation (Neoaptian) is the main source rock in the Sergipe-Alagoas Basin. The Maceió Fm contains organic-rich black shales, marls and calcilutites that were deposited in a lacustrine, non-marine setting which may exhibit ductile behavior during hydraulic stimulation. The higher-quality source rock shales within the Maceió Fm average about 200 m thick (maximum 700 m) and average 3.5% TOC (maximum 12%; Type II kerogen).[18] However, this basin was not assessed due to its structural complexity and lack of available geologic data.

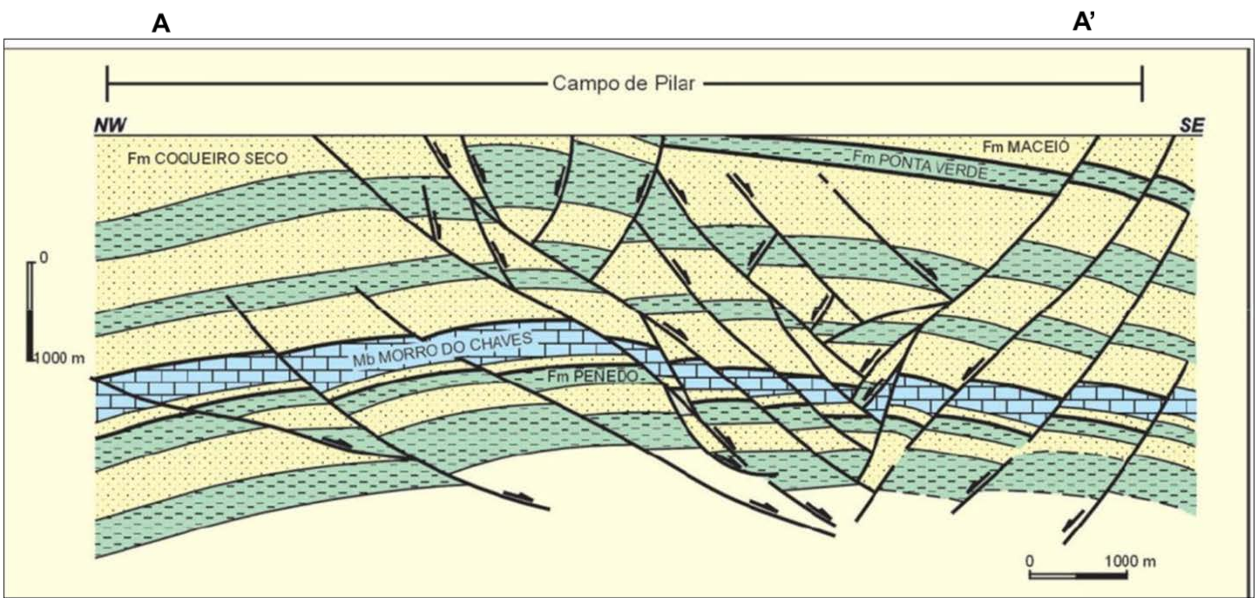
- **São Francisco Basin.** Very little conventional exploration has occurred in this frontier basin in Minas Gerais and there is no significant commercial oil and gas production.[19] Potential source rocks are of Proterozoic age, much older than the productive shales of North America, which are about 400 m thick within a moderately faulted structural setting at depths of 2 to 5 km. Shell reportedly plans to drill its first Brazilian exploration well for unconventional gas in the São Francisco Basin, although this effort appears to be targeting tight sandstone and carbonate formations rather than shale.[20] The São Francisco basin was not assessed by EIA/ARI due to the lack of an established hydrocarbon generation system and the paucity of available geologic data.
- **Taubaté Basin.** Located in southeast Brazil, the Taubaté Basin is a northeast-southwest trending trough related to the Atlantic Ocean continental breakup. The Oligocene Tremembé Formation contains up to 500 m of organic-rich deposits that were deposited within a non-marine lacustrine environment. Within this interval there is a 50-m thick section of laminated black shale with average 10% TOC.[21] However, this deposit is thermally immature oil shale[22] and is not considered prospective for shale gas and oil exploration.
- **Chaco-Paraná Basin.** Not to be confused with the Paraná Basin, the Chaco-Paraná Basin is a large (500,000-km^2) elliptical-shaped depositional feature mainly in northern Argentina, Paraguay and Uruguay. However, only a very small area lies within southern Brazil. The basin contains up to 5 km of early Paleozoic (Ordovician to Devonian) sedimentary and igneous rocks, overlain in the northeast particularly by Cretaceous basalt flows. About 1.2 km of Devonian marine-deposited sandstones (Cabure Formation) and black shales (Rincon Fm) is present. These are overlain by up to 2.3 km of Perm-Carboniferous sandstones and black shales (Sachayoj Fm). The Chaco-Paraná Basin was not assessed due to its small extent and lack of data control within Brazil.

Figure VI-16: Cross-section of the Alagoas Sub-basin, Showing Faulted Pendência and Alagamar Source Rock Shales.



Source: ANP, 2007 (no vertical scale)

Figure VI-17: Detailed Cross-section of the Campo de Pilar Field in the Sergipe-Alagoas Basin, Showing Numerous Closely Spaced Faults.



Source: ANP, 2007

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