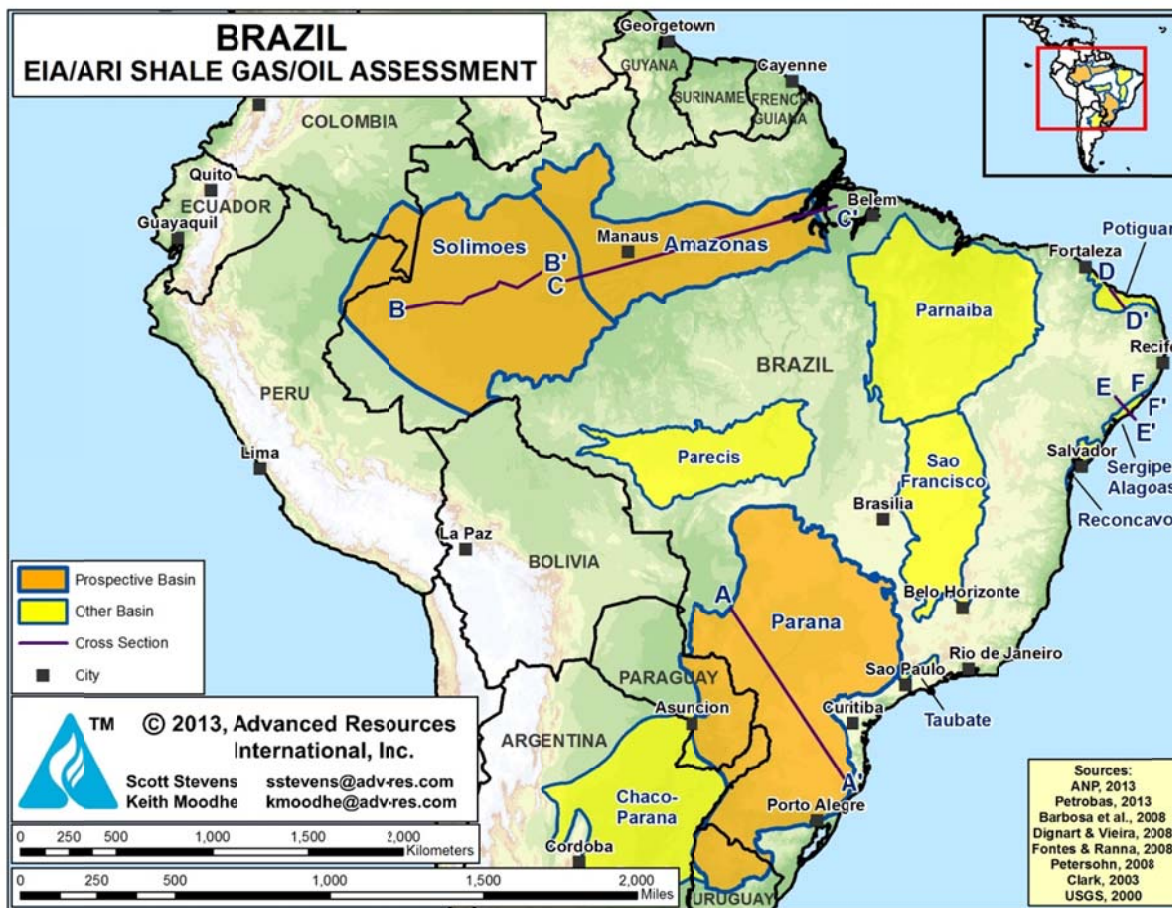


# VI. BRAZIL

## 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 <sup>2</sup> )			Solimoes (350,000 mi <sup>2</sup> )		Amazonas (230,000 mi <sup>2</sup> )			
	Shale Formation	Ponta Grossa			Jandiutuba		Barreirinha			
	Geologic Age	Devonian			Devonian		Devonian			
	Depositional Environment	Marine			Marine		Marine			
Physical Extent	Prospective Area (mi <sup>2</sup> )	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 <sup>2</sup> )	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 <sup>2</sup> )		Solimoes (350,000 mi <sup>2</sup> )	Amazonas (230,000 mi <sup>2</sup> )		
	Shale Formation	Ponta Grossa		Jandiutuba	Barreirinha		
	Geologic Age	Devonian		Devonian	Devonian		
	Depositional Environment	Marine		Marine	Marine		
Physical Extent	Prospective Area (mi <sup>2</sup> )	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 <sup>2</sup> )	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.<sup>1</sup> 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.<sup>2</sup> Petrobras, the national oil company, recently drilled its first shale oil well in Argentina but has not announced plans for shale drilling in Brazil.

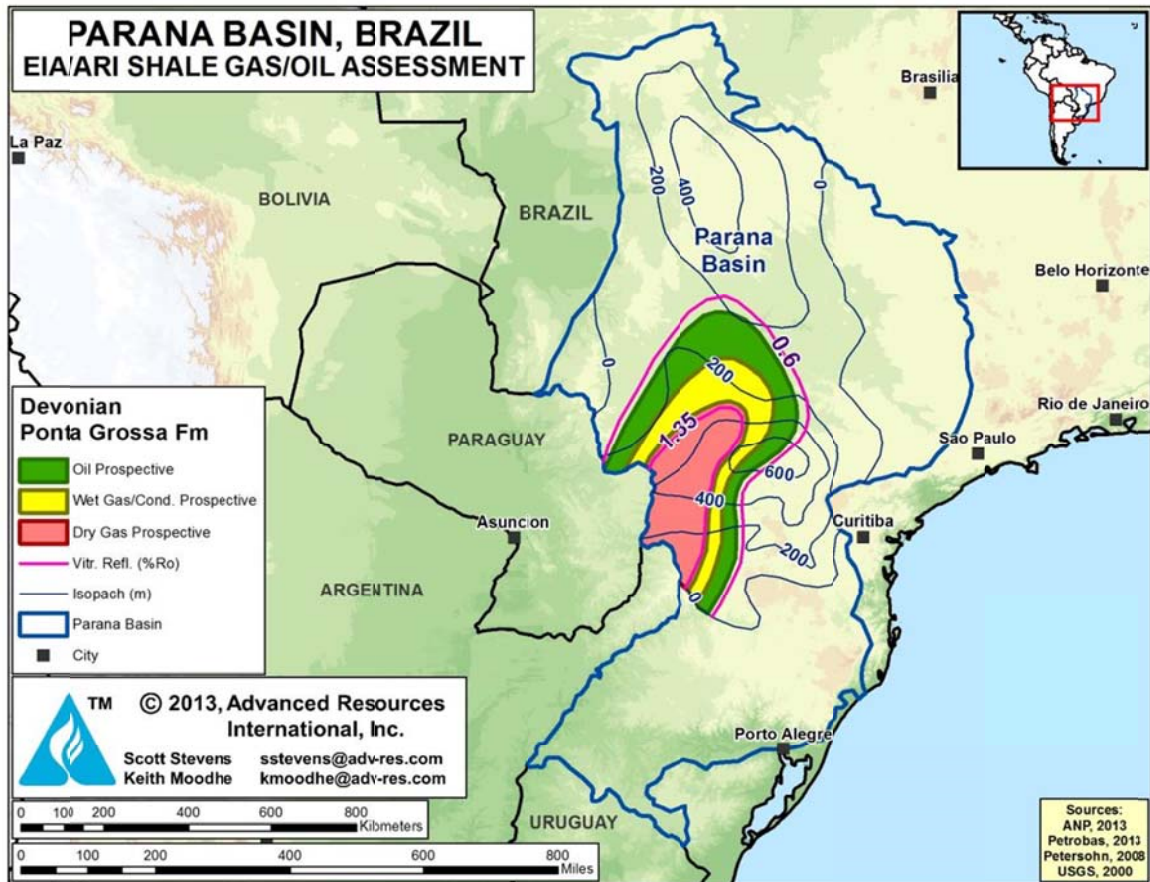
EIA/ARI has assessed the shale resource potential of three of Brazil's onshore basins (Paraná, Solimões, and Amazonas). These basins have prospective shales that sourced commercially productive conventional oil and gas fields as well as sufficient available geologic data for resource analysis. In addition, 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<sup>2</sup>) depositional feature that covers 747,000 mi<sup>2</sup> within Brazil, with additional area in Paraguay, Uruguay, and northern Argentina, **Figure VI-2**. Major infrastructure in the region includes the Brazil-Bolivia and Uruguaiiana-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).<sup>3</sup> 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<sup>2</sup>. In addition, some 30,000 km of 2D seismic have been acquired.<sup>4</sup> 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.<sup>5</sup> 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.

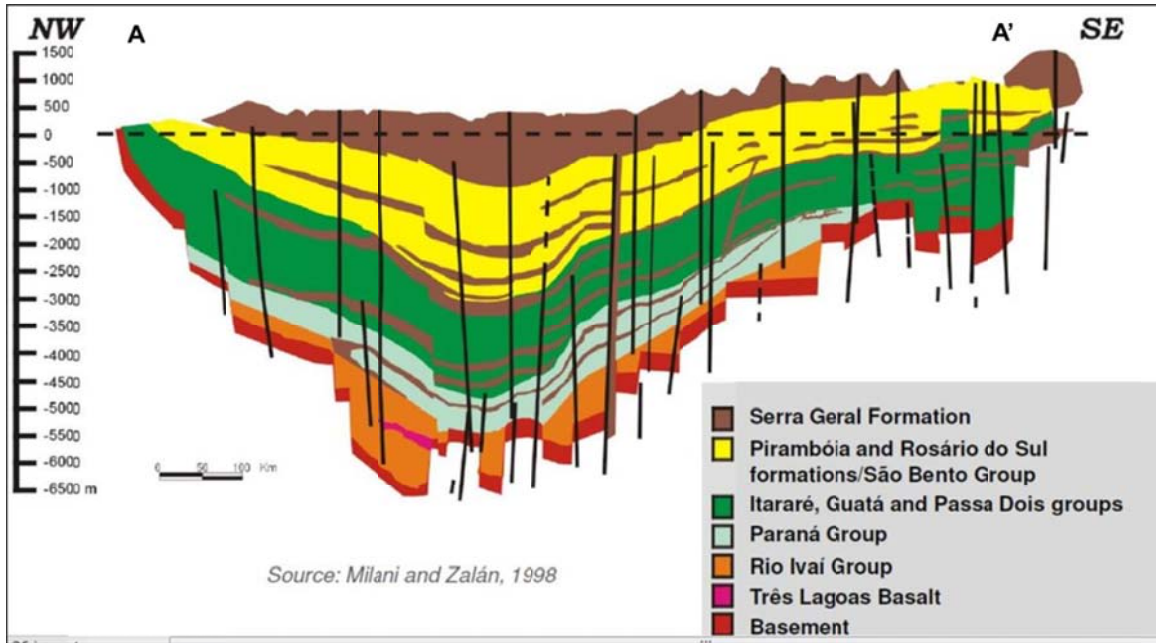
The structure of the Paraná Basin appears to be moderately simple, at least based on available data, consisting of a gentle syncline with minor faulting and secondary folding, **Figure VI-3**. Faults, predominately normal in orientation, are controlled by older basement faults (aulocogens) which separate 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.<sup>6</sup>

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.

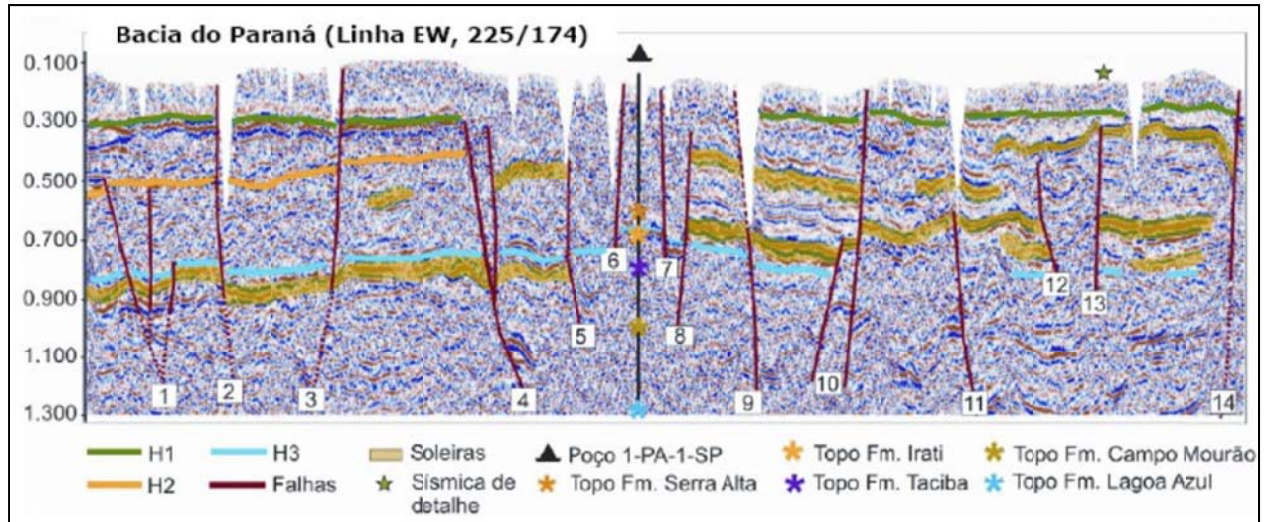
A second less prolific source rock in the Paraná Basin is the Permo-Triassic Irati Formation. This non-marine bituminous unit sourced oil trapped in biodegraded conventional sandstones (tar sands) of the Permian and Triassic Rio Bonito and Pirambóia formations.<sup>7</sup> The Irati Formation is widespread 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,<sup>8</sup> its Brazil extension was not assessed due to low thermal maturity.

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



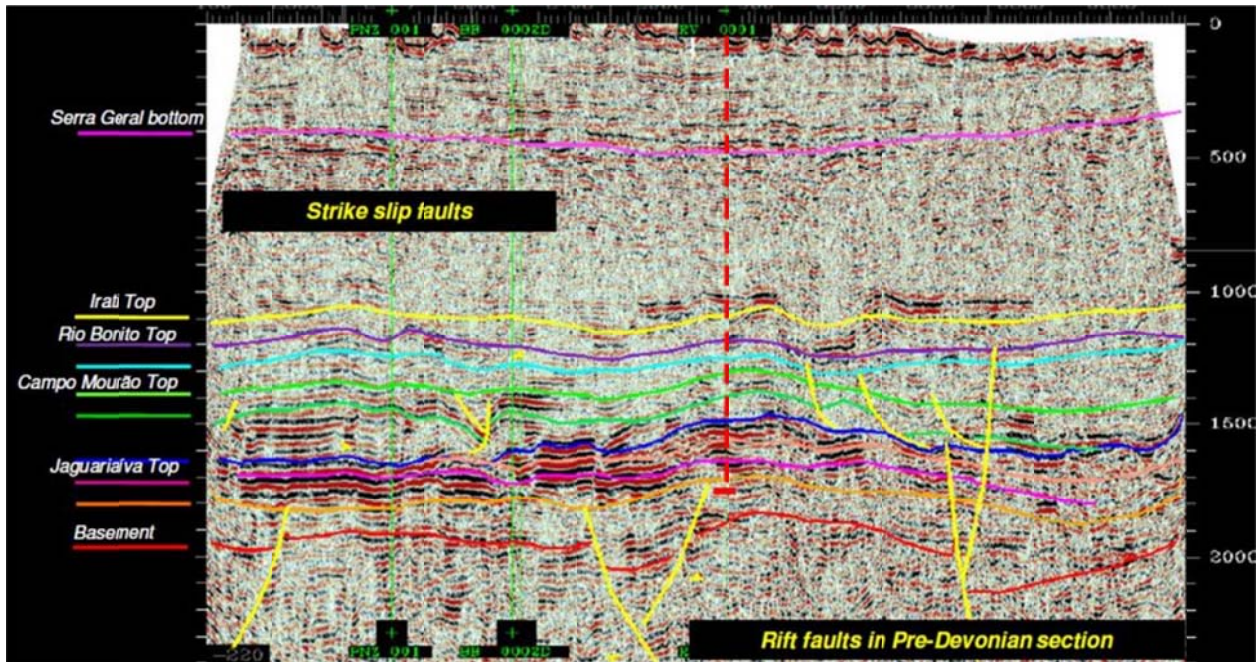
Source: ANP, 2012

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



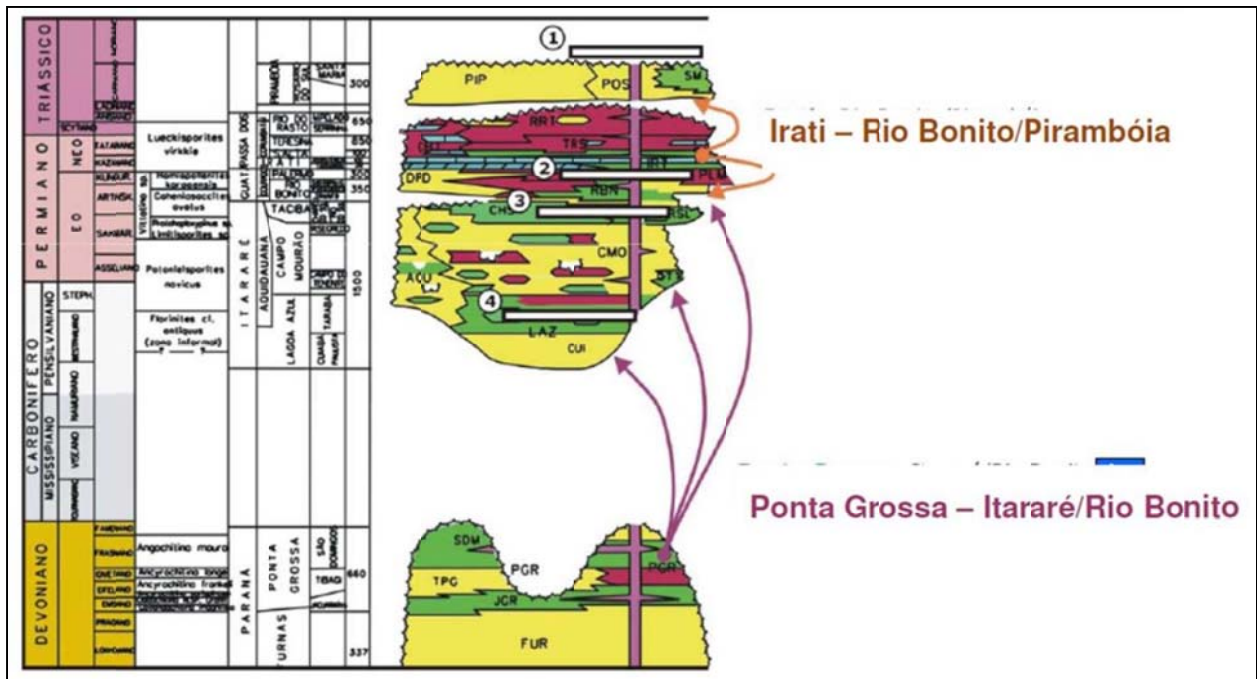
Source: Petersohn, 2003

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<sup>2</sup>, of which 25,600 mi<sup>2</sup> is in the oil window; 18,050 mi<sup>2</sup> is in the wet gas/condensate thermal maturity window; and 22,840 mi<sup>2</sup> 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<sup>2</sup> for shale gas and 11 to 27 million bbl/mi<sup>2</sup> for shale oil depending on thermal maturity window.

## 1.4 Recent Activity

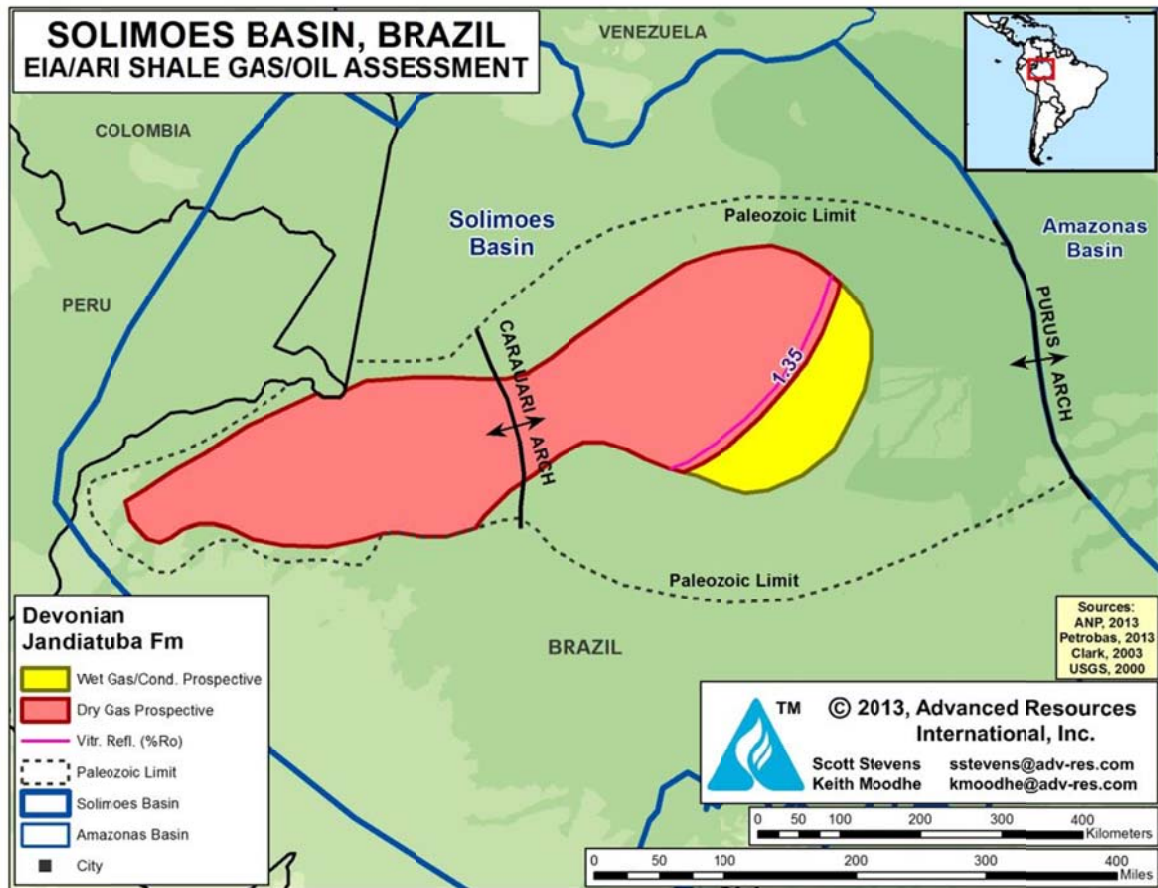
No shale gas/oil exploration activity has been reported in the Brazil portion of the Paraná Basin, although Amerisur Energy has discussed the shale potential of the Cretaceous Irati Fm in the Paraguay portion of the basin.

## 2. SOLIMÕES BASIN

### 2.1 Introduction and Geologic Setting

Located in northern Brazil, the Solimões Basin extends over 350,000 mi<sup>2</sup> 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<sup>3</sup>/d of natural gas from the Carboniferous Juruá Formation sandstone.<sup>9</sup>

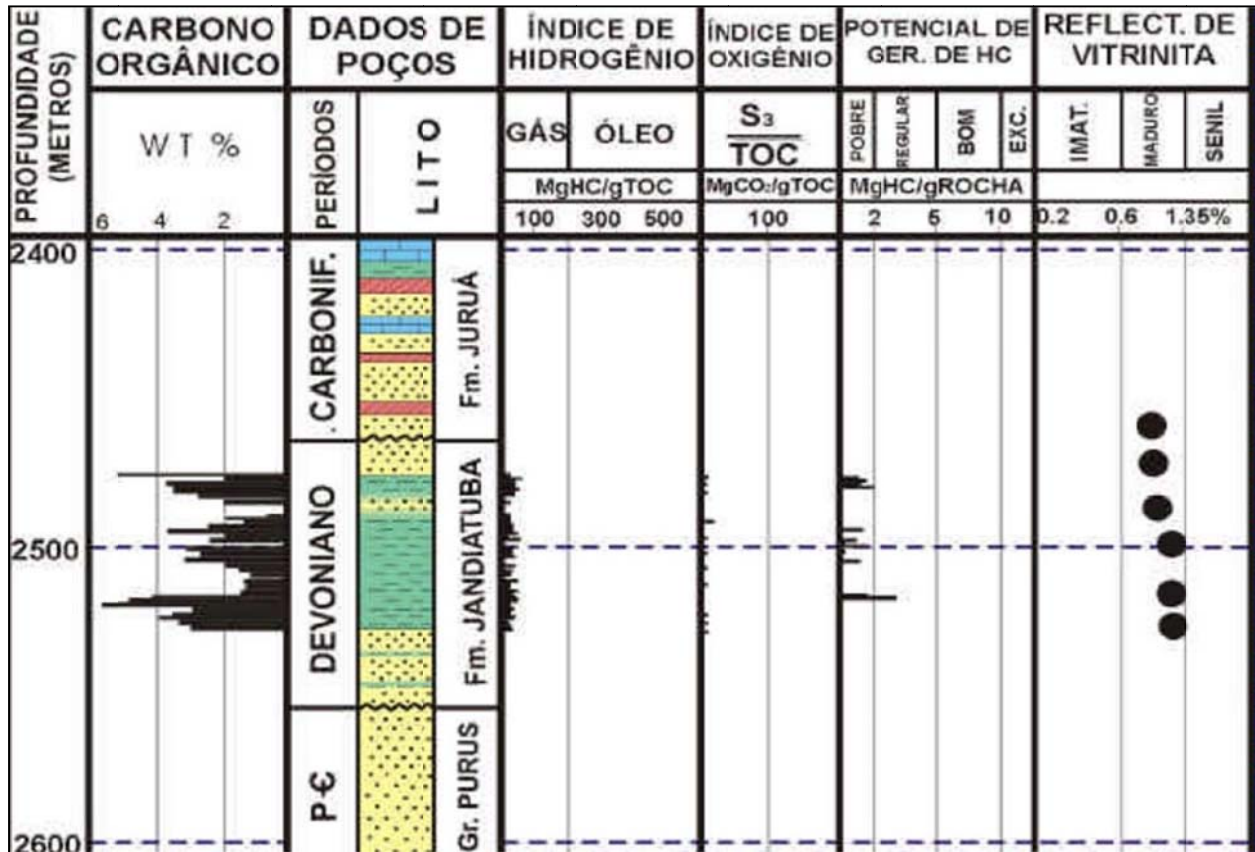
Figure VI-7: Prospective Shale Gas and Shale Oil Areas in the Solimões Basin



Source: ARI, 2013

These conventional reservoirs directly overlie and were sourced by marine-deposited source rocks within the Devonian Jandiutuba (mostly), Jaraqui and Ueré formations. The Jandiutuba 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%).<sup>10</sup>

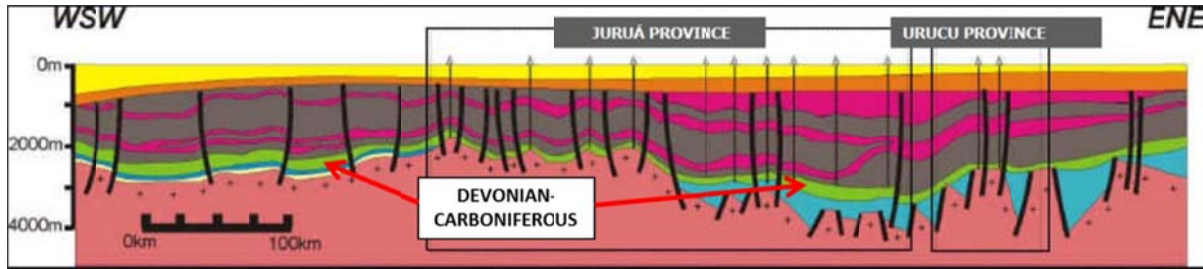
Figure VI-8: Black Shale in the Devonian Jandiatura Formation of the Solimões Basin is about 40 m Thick with 1% to 4% TOC at this Location



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<sup>2</sup>, of which 8,560 mi<sup>2</sup> is in the wet gas thermal maturity window and 54,750 mi<sup>2</sup> 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<sup>2</sup> for shale gas and 5.5 million bbl/mi<sup>2</sup> for shale oil.

## 2.4 Recent Activity

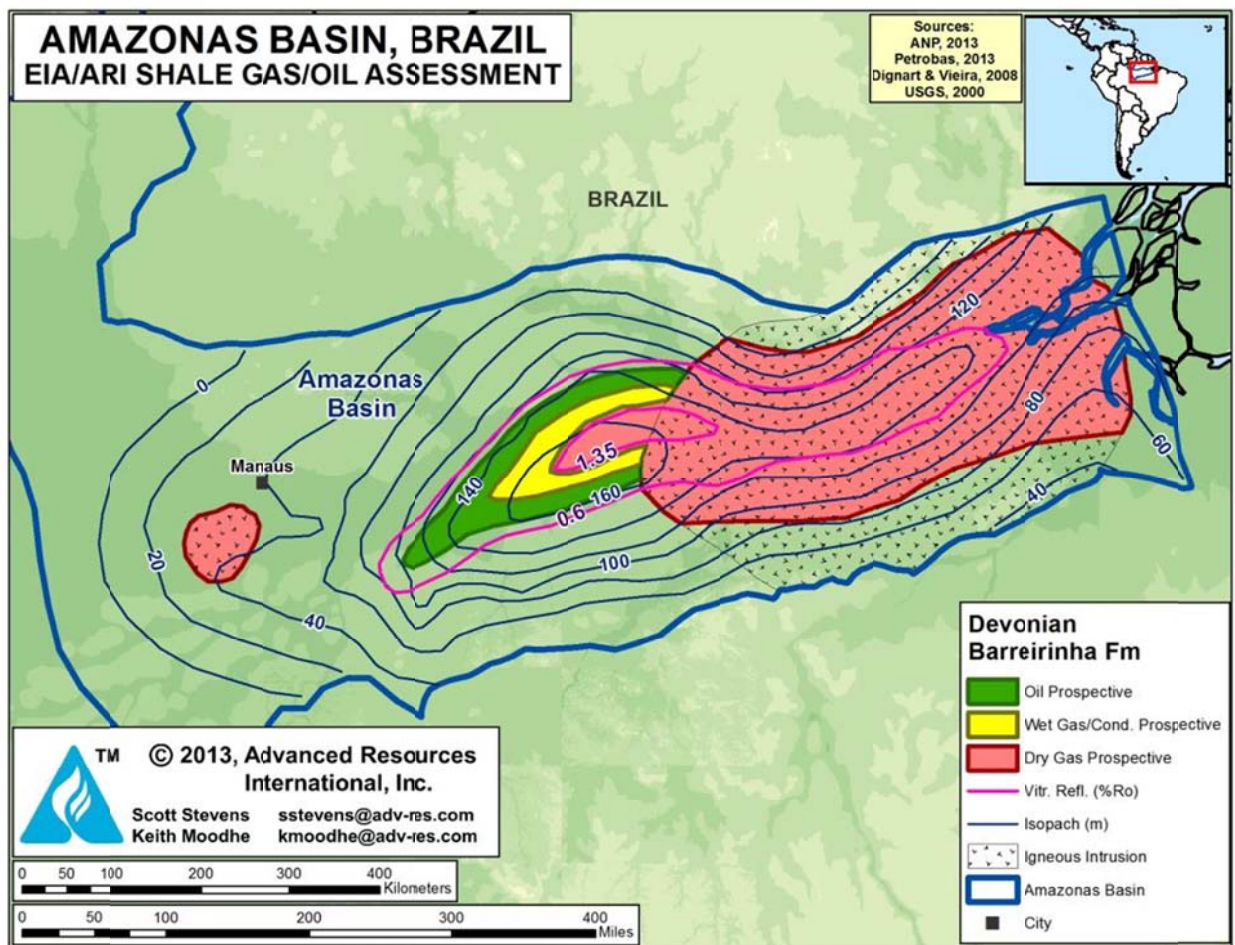
No shale gas/oil exploration activity has been reported in the Solimões Basin.

### 3. AMAZONAS BASIN

#### 3.1 Introduction and Geologic Setting

Extending over more than 230,000 mi<sup>2</sup> 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.

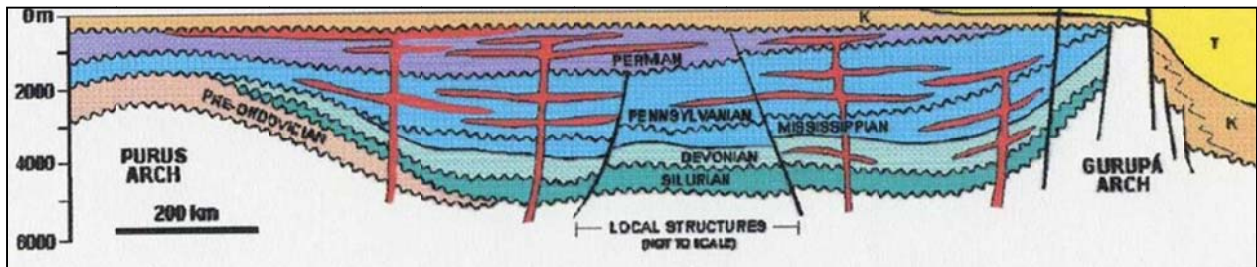
Figure VI-10: Prospective Shale Gas and Shale Oil Areas in the Amazonas Basin



Source: ARI, 2013

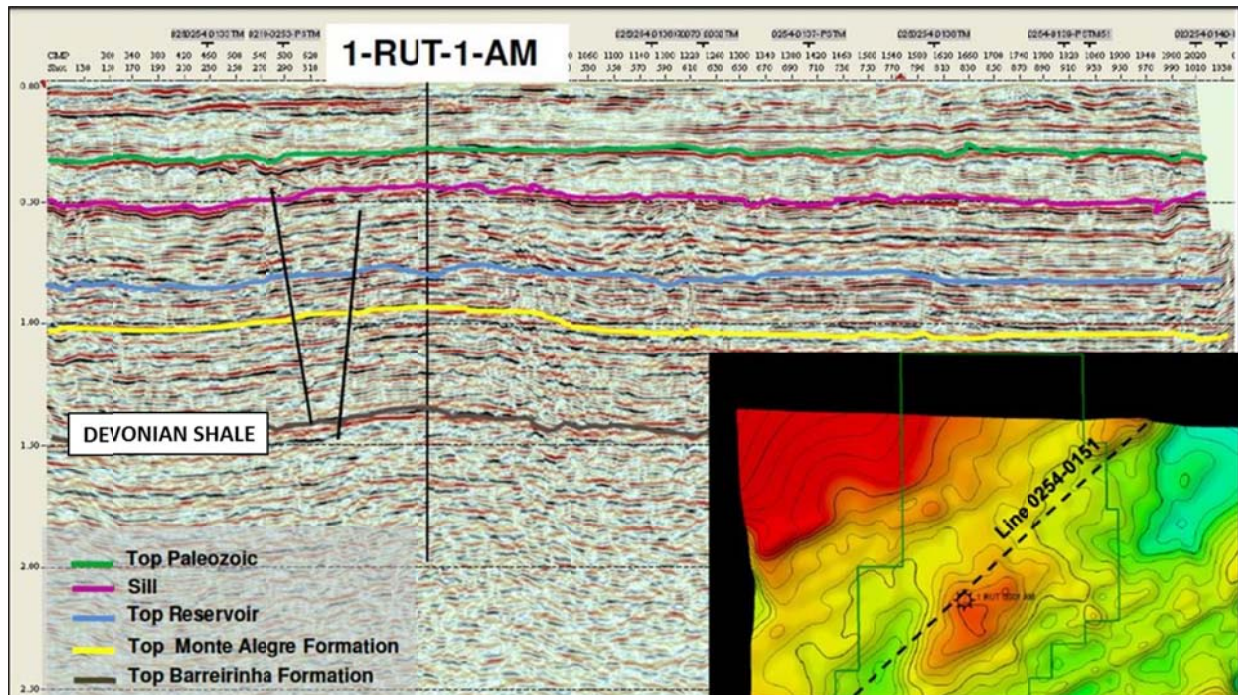
The Amazonas Basin contains up to 5 km of mostly Paleozoic sedimentary rock that are covered by Mesozoic and Cenozoic strata, **Figure VI-11**. While not structurally complex, the Amazonas Basin was extensively intruded by igneous activity during the Early Jurassic, particularly in the eastern half of 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.<sup>11</sup> 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<sup>2</sup>, of which 5,520 mi<sup>2</sup> is in the oil window; 3,260 mi<sup>2</sup> is in the wet gas and condensate window; and 44,890 mi<sup>2</sup> 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<sup>2</sup> for shale gas and 9 to 18 million bbl/mi<sup>2</sup> for shale oil.

### **3.4 Recent Activity**

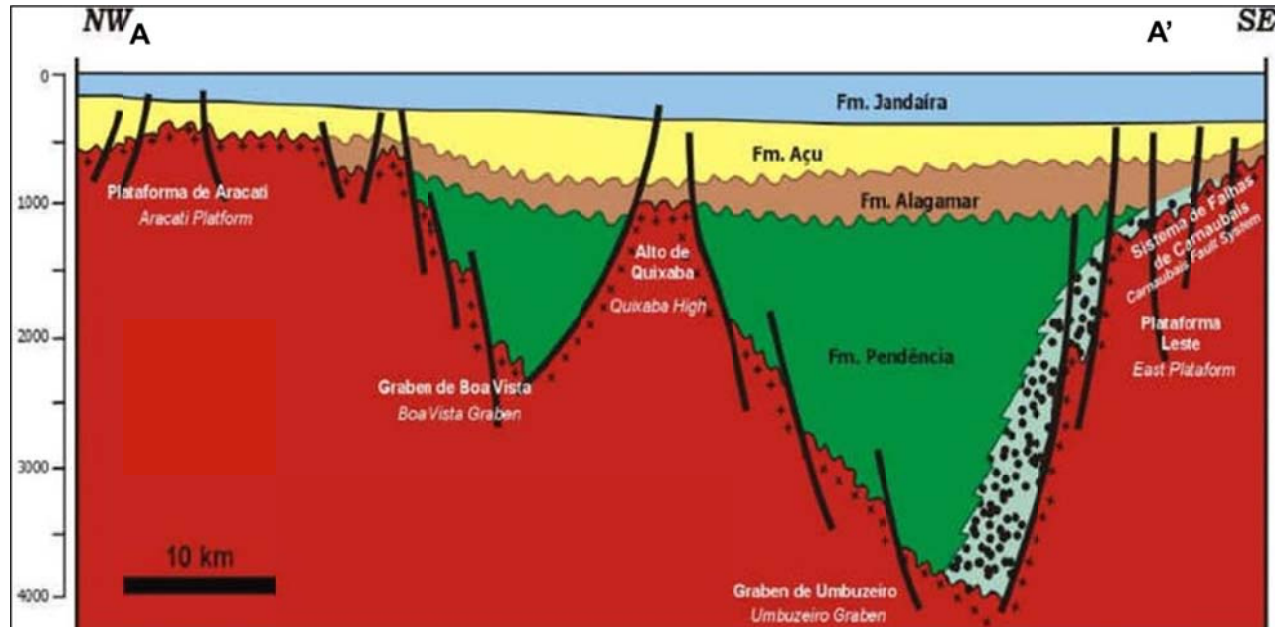
No shale gas/oil exploration leasing or drilling activity has been reported in the Amazonas Basin.

#### 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<sup>2</sup> 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.<sup>12</sup>

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



Source: ANP, 2003

The Upper Cretaceous (Barremian) 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.<sup>13</sup> 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.

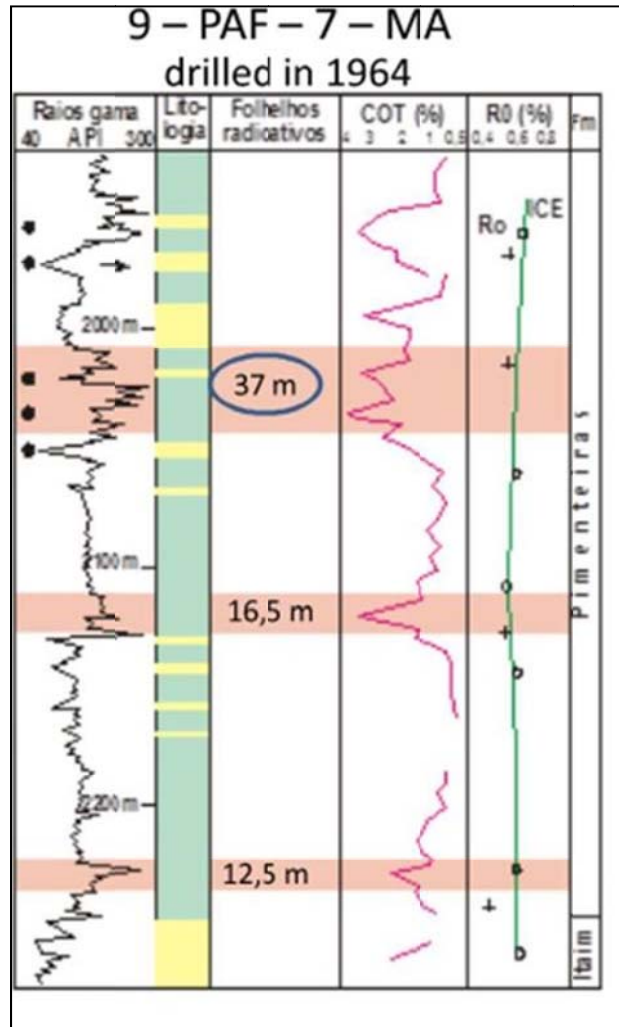
- **Parnaíba Basin.** Also located in northeastern Brazil, this large (600,000-km<sup>2</sup>) circular basin contains up to 3.5 km of sedimentary rocks within a relatively simple -- albeit heavily intruded -- structural setting. The Devonian Pimenteiras Formation contains marine black shale up to 300 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.<sup>14</sup>

**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.<sup>15</sup>

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 Parnaíba 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 Pimenta Shale in the Parnaíba Basin



Source: ANP, 2003

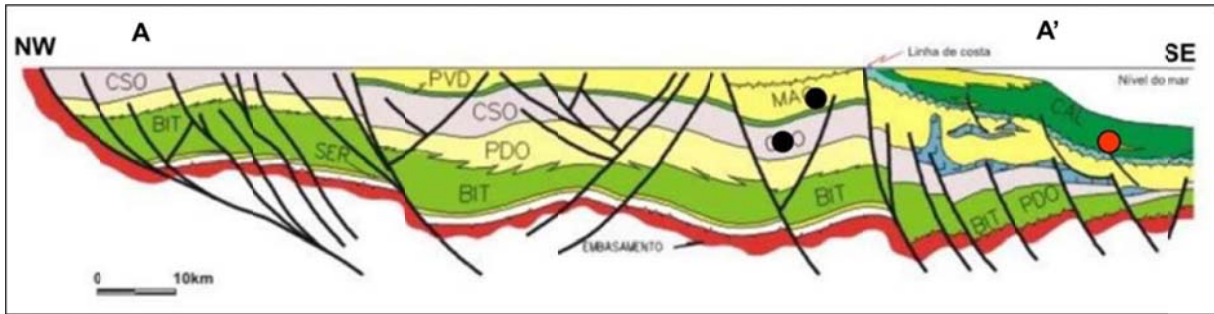
- Recôncavo Basin.** One of many failed rift basins in eastern Brazil, the Recôncavo Basin was the country's first productive petroleum basin. Over 6,000 wells have drilled, of which some 1,800 extent producing wells make 50,000 bbl/day of oil. The Gomo Member of the Lower Cretaceous Candeias Formation, deposited in a lacustrine environment during early rifting, is considered the main source rock.<sup>16</sup> 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.



The Cretaceous Maceió Formation (Neoptian) 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).<sup>18</sup> However, this basin was not assessed due to its structural complexity and lack of available geologic data.

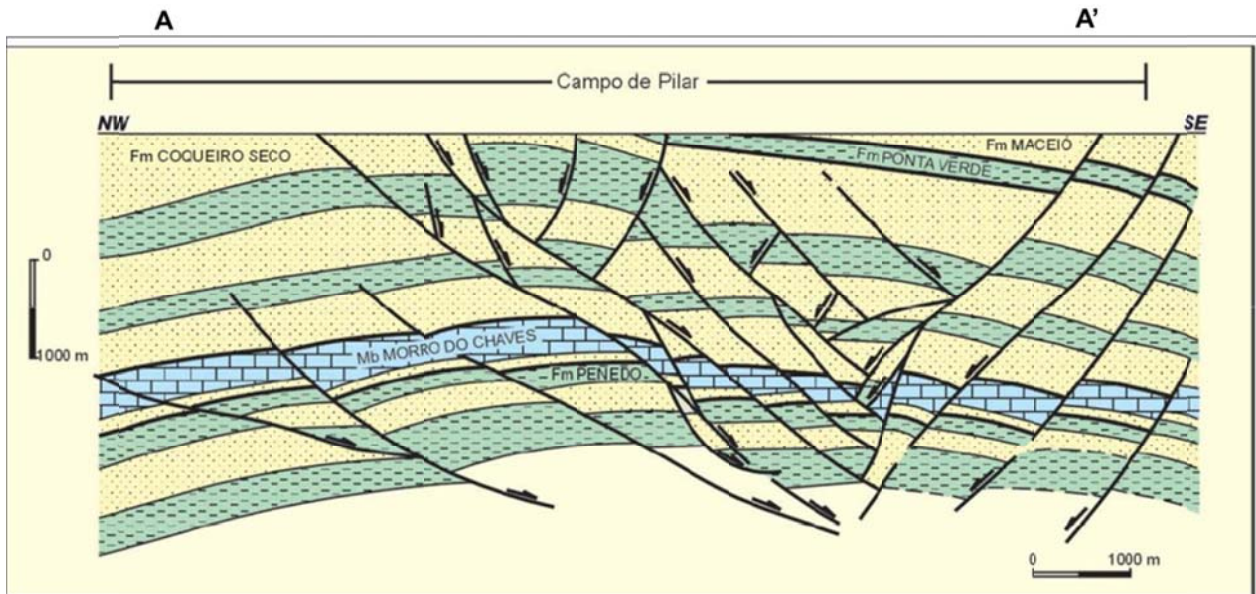
- **São Francisco Basin.** Very little conventional exploration has occurred in this frontier basin in Minas Gerais and there is no significant commercial oil and gas production.<sup>19</sup> Potential source rocks are of Proterozoic age, much older than the productive shales of North America, which 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.<sup>20</sup> 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.<sup>21</sup> However, this deposit is thermally immature oil shale<sup>22</sup> 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<sup>2</sup>) 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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