Petroleum Systems of South American Basins

Antonio Manuel Ferreira de Figueiredo and Edison José Milani

The sedimentary basins of South America may be ordered into a few classes related to the main tectonic-stratigraphic events that have originated and modified the South American Plate. These events were responsible not only for the present distribution of basins over the plate, but also for the volumes of hydrocarbons generated and effectively accumulated in these basins, and under an exploratory perspective, for their remaining potential.

The tectonic and stratigraphic evolution of the most representative basins of the South American Continent, discussed in this volume (see the text by Milani and Thomaz Filho), resulted in the creation of several classes of basins and hence in the generation of some very distinctive types of petroleum megasystems, that is, groups of basins presenting similar processes and conditions of hydrocarbon generation, migration and accumulation.

This concept was introduced by Dow (1974), while he was working for AMOCO. Since then, this concept has been extensively developed and used by most petroleum geoscientists. In this paper we will emphasize the source rock as the main factor to characterize the megasystem. With this in mind, the petroleum resources of the South American basins can be grouped into five petroleum megasystems:

- Subandean Megasystem, present from the N of Argentina to the S of Peru;
- Austral Rifts Megasystem, in the southern part of South America;
- Andean and Caribbean Foreland Megasystem, present from the N of Peru to Venezuela and Trinidad-Tobago;
- South Atlantic Rift Megasystem, present along the Atlantic coast of Argentina and Brazil;
- Intracratonic Megasystem, present in the interior sag basins of the Brazilian continental area.

These five megasystems include almost all reserves of gas and oil ever found in South America.

Reserves and Petroleum Megasystems

The petroleum systems of South America have been studied and analyzed in great detail by several authors and published mainly as Special Publications of the American Association of Petroleum Geologist. These special publications are very complete and comprhensive reviews, and include the Treatise of Petroleum Geology, the Atlas of Oil and Gas Fields (1991) and the Petroleum Basins of South America (Memoir 62, 1995). The Classic Petroleum Provinces (1990), published by the Geological Society of London, is also a very important reference. In more recent years other studies, made and published mainly by geoscientists on the geochemistry of petroleum, have contributed decisively to the understanding and clarification of the main aspects of these megasystems. Papers such as those of the AAPG Hedberg Research Conference of 1994, and of Mello and Trindade (1996), are excellent examples of these studies. Kronman *et al.* (1995) analyzed the oil and gas discoveries in the last decade in the South American basins, and forecast the remaining resources.

Excluding the Middle East, the South American countries, plus Mexico, have the largest volume of oil reserves of the Earth, being therefore of prime importance to future development, not only for the region, but also for the entire world. Taking into consideration only the South American basins Kronman's studies have indicated that the average success ratio for wildcat drilling during the last decade was between 20% and 30%, and is not declining. This may be interpreted as an indication that these basins may still hold large amounts of petroleum to be discovered. Even with the decrease of the numbers of wildcat wells drilled in the recent years, this ratio has been mantained and several giant oil and gas fields have been discovered very recently, including Marlim, Albacora and Roncador in the deep waters of the Brazilian Campos Basin; Cupiaga and Cusiana in deep reservoirs of the Llanos Basin in Colombia; the Camisea Gas Complex in the Peruvian jungle; and El Furrial in deep reservoirs of Maturín Basin, Venezuela. As a general result the oil and gas reserves of the South American basins have effectively increased, and the growing utilization of the most modern technology in petroleum research has been the fundamental key in achieving this goal.

Based on work of the authors cited above and data published around the world, it is possible to estimate the possible *in situ* volumes generated by the five megasystems:

Petroleum Megasystem	Age of Source Rock	Age of Reservoir	In Situ Volumes ($x10^6$bb/EO)
Subandean	Silur/Devon.	Paleoz/K/Terc	40 000
Austral Rifts	Jur/Eo-Cret.	Cret/Terc.	70 000
Andean/ Venezuelan Foreland	Mid-Cret/ Late Cretaceous	Cret/Terc.	2 000 000
South Atlantic Rifts	Early Cret/ Mid-Cretaceous	Cret/Terc.	100 000
Intracratonic	Devonian	Paleozoic	20 000

It becomes clear that the petroleum megasystem associated with the basins affected by the lateral displacement of the Caribbean Plate along the northern margin of the South American Continent in Venezuela and the foreland basins of Colombia, Ecuador and Peru, is, by far, the richest megasystem. This fact is related to the previous existence of optimum conditions for the development of thick and extensive sections of pelitic rocks with high content of organic matter, in geological conditions very similar to those occurring in the Tethys Sea of the Middle East, as well as favourable tectonic conditions for huge traps resulting from plate interaction and collision.

The BP Statistical Review of World Energy, published at the end of 1998, indicated that the proven world oil reserves are around 1.053 billion barrels, of which the contribution of the South American petroleum systems is a modest 89.5 billion barrels (8.3%). According to the same publication, the proven world gas reserves are about 5.170 trillion cubic feet, of which the contribution of South American basins is about 219 billion cubic feet (4.3%). It is believed that this large difference in terms of oil and gas content in the South American basins reflects the absence of a competitive and developed gas market on the continent, resulting in low prices for this energy source and the consequent lack of incentive to exploration, rather than the absence of gas in the basins.

If it is assumed that the current world production is about 75 million barrels of oil per day, the world reserve/production ratio (R/P) would be around 41 years for oil and 63 years for gas. For South America, these figures are 38 years and 71.5 years respectively. Again, it is clear that in the near future gas will become very important, and a growth of its presence in the energy matrix of the South American countries will be imperative.

The table shows the reserve and production figures for oil and gas in South America:

Country	Oil and Gas Reserve ($x10^9$bbl/TCF)	Oil and Gas Production ($x10^3$bbl/day-10^9m^3/year)
Argentina	2.6 – 24.1	890 – 29.3
Bolivia	0.5 – 4.3	30 – 3.2
Brasil	7.1 – 8.0	990 – 6.5
Colombia	2.6 – 6.9	765 – 6.3
Ecuador	2.1 – 3.7	385 – 0.0
Peru	0.8 – 0.5	115 – 0.0
T. & Tobago	0.5 – 8.3	135 – 8.6
Venezuela	72.6 – 142.5	3335 – 29.9

Source – BP Statistical Review

In order to understand and describe the petroleum megasystems referred to above, the characteristics of each megasystem in terms of the source rocks, main reservoirs, traps, migration pathways and timing will be described hereunder. Comments are made on the accumulation and preservation of the hydrocarbons, and an example of each type of petroleum megasystem will be made with reference to a specific basin and/or giant field.

Subandean Basins Petroleum Megasystem

In this petroleum megasystem are included several types of basin that were affected by the plate tectonics regime responsible for the generation of the Andean Chain that developed along the western margin of the South American Plate, resulting from collision of the South American and Nazca/Pacific plates.

These basins developed as the result of several cycles of subsidence and accumulation of sedimentary packages, alternating with periods of uplift and erosion (polycyclic basins). They occur from the northern part of Argentina (Northwestern Basin) and in Bolivia to the southern part of Peru (Ucayali/Madre de Dios basins).

In these basins (Fig.1) the petroleum megasystem is characterized, essentially, by oil and gas generation with source in Paleozoic shale (Late Silurian-Devonian) deposited in an open marine environment (marginal Panthalassan Basin). These rocks hold a high content of organic matter, and are associated with the basal section of a very thick (several hundreds of metres) pelitic transgressive sequence that onlaps sandy siliciclastic deposits accumulated in shallow epicontinental seas.

In the geological context of the Subandean Basin in northwestern Argentina and southern Bolivia there occurs the Kirusillas Formation (Late Silurian), and the Icla and Los Monos formations (Devonian), responsible for the generation of large amounts of oil and gas accumulated in intercalated sandstone sequences known as the Santa Rosa and Huamampampa formations. Besides, other Paleozoic (San Telmo, Tarija, Tupambi, and Escarpment), Cretaceous (Ichoa, Cajones and Petaca) and Tertiary (Tranquitas and Chaco) clastic reservoirs have their source in these rocks.

Andean tectonics was responsible for the development of a very large and continuous fault and fold belt striking N-S, and affecting mainly the western margin of the basin. Several pulses of compression originated huge structural traps residing in complex anticlinal systems associated with thrust faults with detachment in the less competent beds, resulting in shortening of several tens of kilometres and in the thickening of the Los Monos shaly section.

Asymmetrical folds with very tight limbs constitute most of these structures. However, stratigraphic and combined traps are also present, and these are mainly related to the channelling of fluvio-glacial sandstone deposited in large valleys sculptured by deglaciation-related mass flows during the Carboniferous.

The main epoch of generation and migration of hydrocarbons seems to be correlated with the last and very recent tectonic pulse of Andean uplift during the Miocene and Pliocene. During this event, the source rocks were rapidly depressed in the basins and folded into synclinoria, attaining both the oil and the gas window. As a result of this rapid deepening, large amounts of oil, and principally gas, were produced and trapped in the newly formed structural features. These accumulations in the deep reservoirs of Devonian age have been discovered only recently due to the technological advances that have permitted subsurface mapping and drilling of wells below depths of 5000 m through shallow high-pressures zones in search of hydrocarbons in the crest of the anticlines.

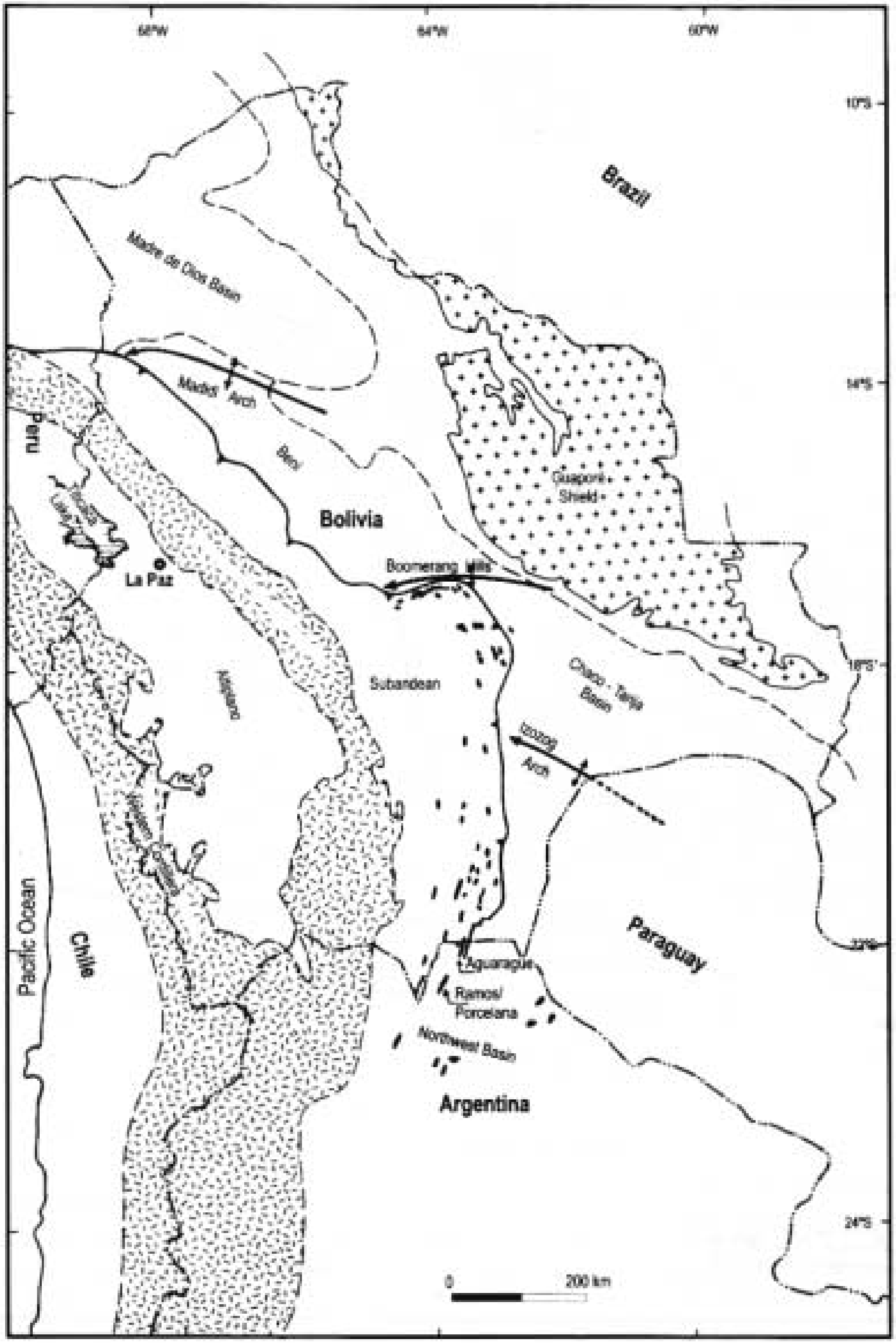


FIGURE 01 – Location map of the southern portion of the Subandean Petroleum Megasystem, in Argentina and Bolivia, displaying the main structural features, associated basins and major oil and gas fields.

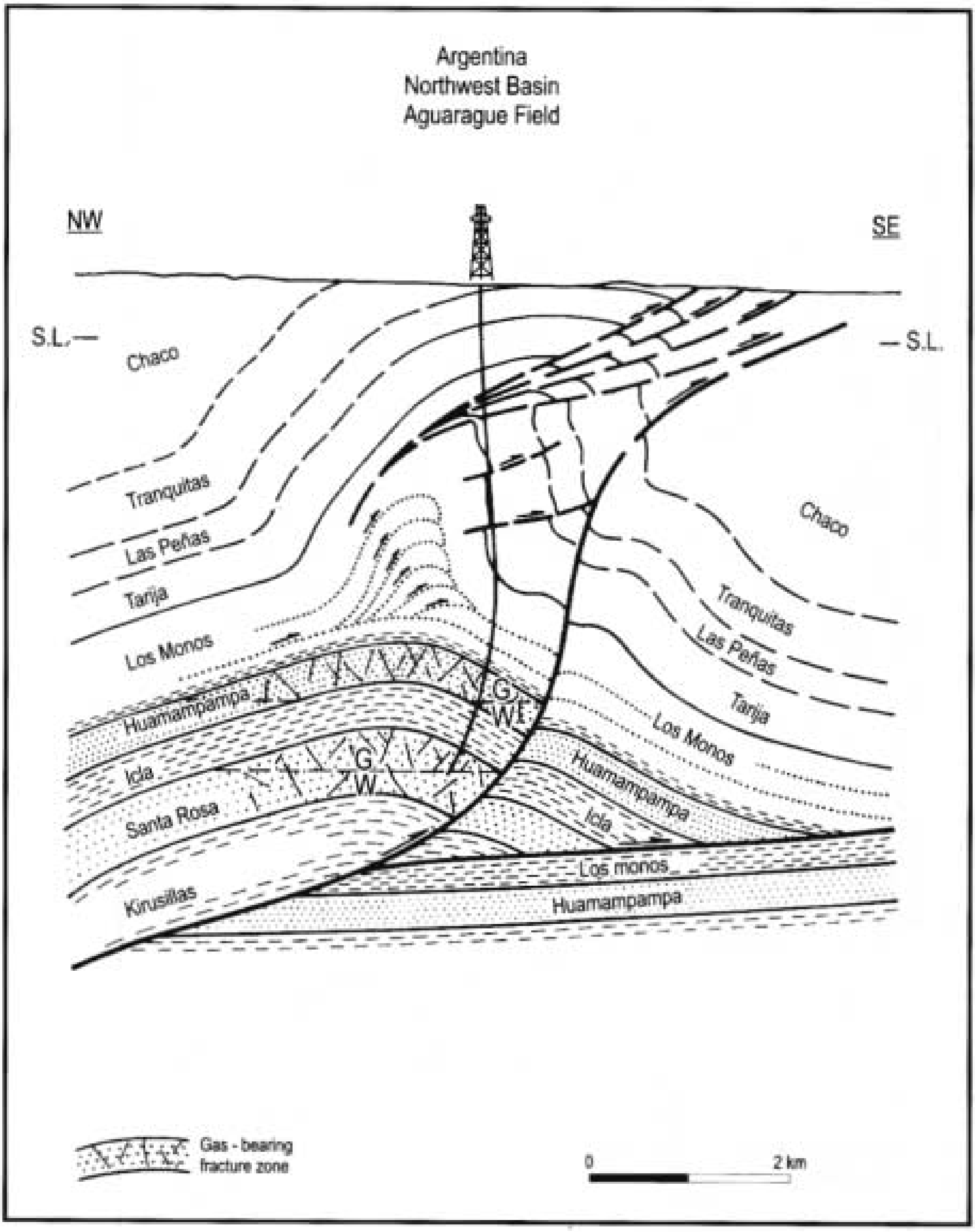


FIGURE 02 – Schematic structural cross-section of the Aguarague Field, Northwest Basin, Argentina (modified after Grieco, 1991)

The main reservoirs consist of very thick sandstone sequences composed of clean fine to very fine-grained quartzarenite beds, deposited on a shallow marine platform during the Devonian. Normally, these sandstone units are highly cemented by extensive secondary quartz overgrowths and, due to their high degree of compaction, developed a very dense network of natural fractures in order to accommodate the intense folding caused by the stress field.

The fracture zone is the key to the excellent reservoir properties displayed by these sandstone units, and this zone is only present as a narrow band associated with the crest of the anticlinal apexes. This feature causes great difficulties in the exploration for this target, since the position of these apexes is hard to interpret from seismic data. The poor quality of the seismic data is directly related to the rough topography and also to the structural complexity of the fold belt. Very often there occurs the lateral migration of the position of the crest of the fold with depth, resulting in problems in using surface mapping or shallow seismic horizons to orient the drilling objectives in the deeper levels of the anticline.

Included in this megasystem may be cited the giant gas pools occurring in the Northwestern Basin encompassing the Subandean folded belt in Argentina and Bolivia. Such pools include those of the Ramos, Aguarague, San Alberto and San Antonio, Colpa-Caranda and El Palmar fields. Small and shallow oil fields are normally associated with these gas pools. Although this type of field is not well known, recent technological advances in drilling and seismic surveying have led to the discovery of several very large gas fields with similar volumes as those found in the Camisea Complex of southern Peru that is also part of the same megasystem.

These basins contain a reserve having a potential of around 15 trillion cubic feet of gas (TCFG) in addition to the 11 TCFG already discovered in the Camisea Complex of the Ucayali Basin. These gas resources will supply the energy needs of the southern South American countries for very many years to come. It is now proposed to describe in further detail some of the representative giant gas accumulations associated with this megasystem.

Ramos-Porcelana and Aguarague Fields

These gas fields are situated in the Northwestern Basin, northern Argentina, in the vicinity of the City of Salta. This basin (Fig. 1) has geological continuity with the Subandean folded belt area of southern Bolivia, to the N, where very recent discoveries have been made in the same Subandean Ranges (San Alberto, Itau, and San Antonio fields).

The Ramos-Porcelana Field is situated on the same anticlinal structure, some 70 km long, in Argentina. On the Bolivian side, this structure is more than 70 km long, and at least two giant gas pools at its apex are being evaluated (San Alberto and Itau). The folded area is about 10 km wide, but the gas-bearing zone is restricted to the crest of the fold, where the Huamampampa reservoirs are intensely fractured. The original matrix porosity is reduced by cementation reaching values around 3 to 4%, which helps to accommodate large gas volumes.

These fields, as well as the Aguarague Field in a parallel anticlinal structure to the E may hold more than 3 TCFG each. The gas is contained in two main reservoirs situated below the Los Monos and Icla formations, the main Devonian source rocks, and above the Kirusillas Formation. These highly fractured siliciclastic sequences normally occur in the upper part of the Huamampampa, Icla and Santa Rosa formations (Fig. 2). The gas column in these reservoirs may be as thick as 600 m.

The natural fracture system created by the regional stress field may be sub-divided into two sub-systems. The first consists of large and open fractures responsible for the very high gas production, and the second consists of a very dense network of small and closely-spaced fractures that act together with the original matrix porosity as the stocking element to accumulate the large gas volume.

This dual system is extremely efficient, and allows open flow production that is locally greater than 1.5 million cubic metres of gas per day in each reservoir. Therefore, each well may present a production capacity exceeding 2 million cubic metres per day. This volume of gas is sufficient to sustain a thermoelectric plant producing 500 MW.

The source rock of these gas fields, and also of the small oil pools in the Late Carboniferous, Cretaceous and Tertiary sands, are the aforementioned Los Monos, Icla and Kirusillas formations of Late Silurian to Devonian age. The basal part of these marine shale sequences is very rich in algae-derived organic matter, and since they onlap over the main reservoirs the migration pathway becomes very short and only primary migration may be required. Fault zones also provided a way by which the oil and gas was able to reach the shallow reservoirs, locally only a few km above the source rock.

The traps are structural (Fig. 2), and the hydrocarbons are retained in the apexes of the anticlines, sealed by thick shale sections. The spill-point is apparently controlled by the low-angle reverse faults, and in some areas such as in Ramos Field there may occur the thickening of the reservoir due to the presence of duplex features affecting the Huamampampa sequence, doubling the length of the fractured pay-zones, and allowing the storage of very large reserves.

Camisea Complex

This complex of gas-bearing structures is situated in the southern part of the Ucayali Basin in Peru, close to the border between this basin and Madre de Dios Basin (Fitzcarrald Arch). This complex was found in the first years of the 1980s and is situated in the middle of a tropical rain forest, about 500 km S of the City of Lima, Peru (Fig. 3).

It is formed by at least, three gas accumulations known as Cashiriari, San Martín and Miyapa and holds around 11 TCFG and 600 million barrels of associated condensate, equivalent to a reserve of 2.6 billion barrels of oil.

The gas is trapped in anticlinal folds associated with low-angle reverse faults and several reservoirs are present in this structure (Fig. 4). The production capacity of these reservoirs is around 800 000 cubic metres per day.

Evaluation wells drilled very recently indicate that the main reservoirs, formed by Cretaceous sandstone units, deposited in fluvial and fluvio-deltaic environments (Cushabatay, Agua Caliente and Vivian formations), are extensively fractured by compression. However, long-duration

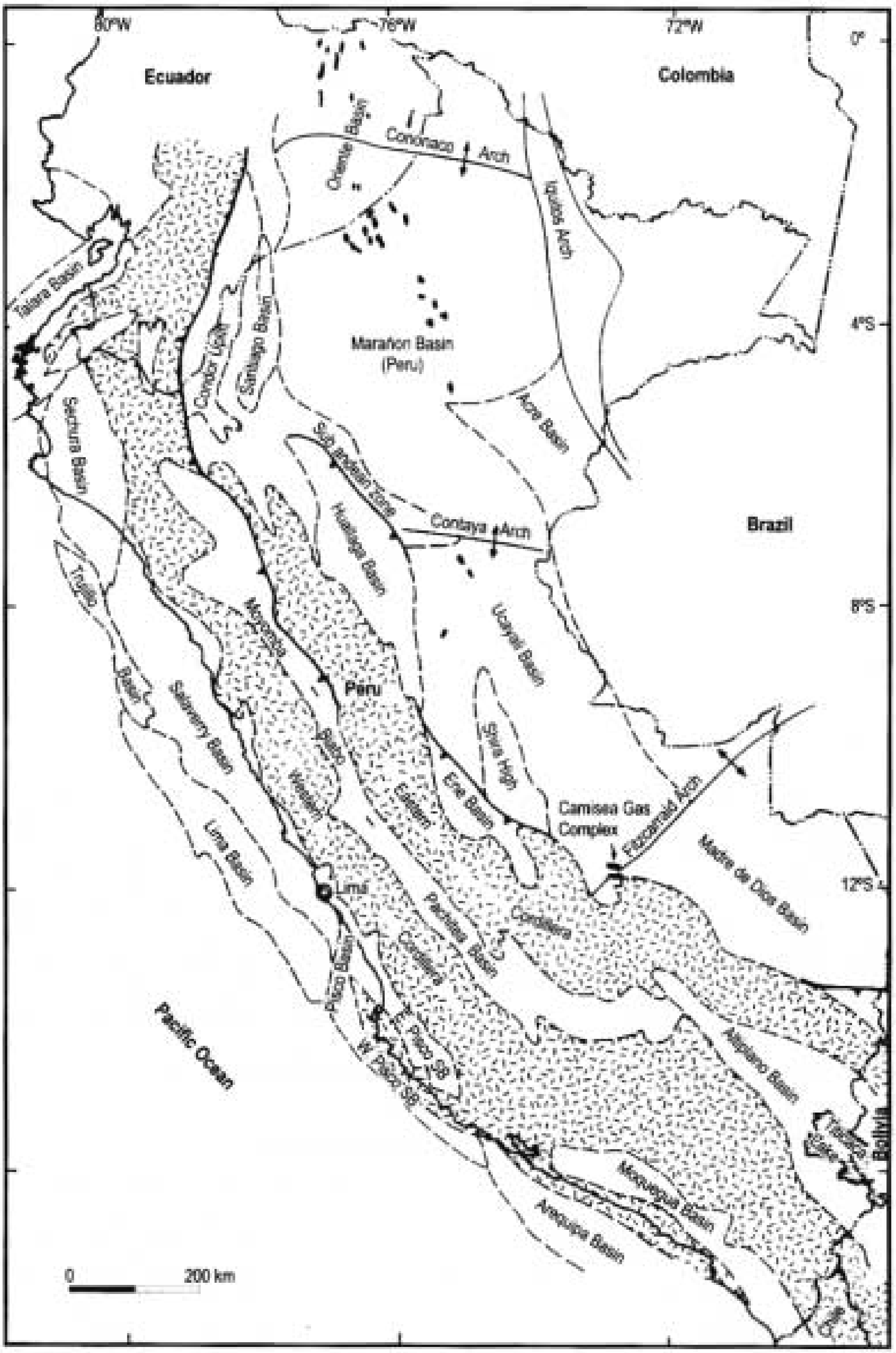


FIGURE 03 - Location map of the northern portion of the Subandean Petroleum Megasystem, and the southern portion of the Andean Foreland Petroleum Megasystem, in Peru, displaying the main structural features, associated basins and oil and gas fields (Camisea Gas Complex).

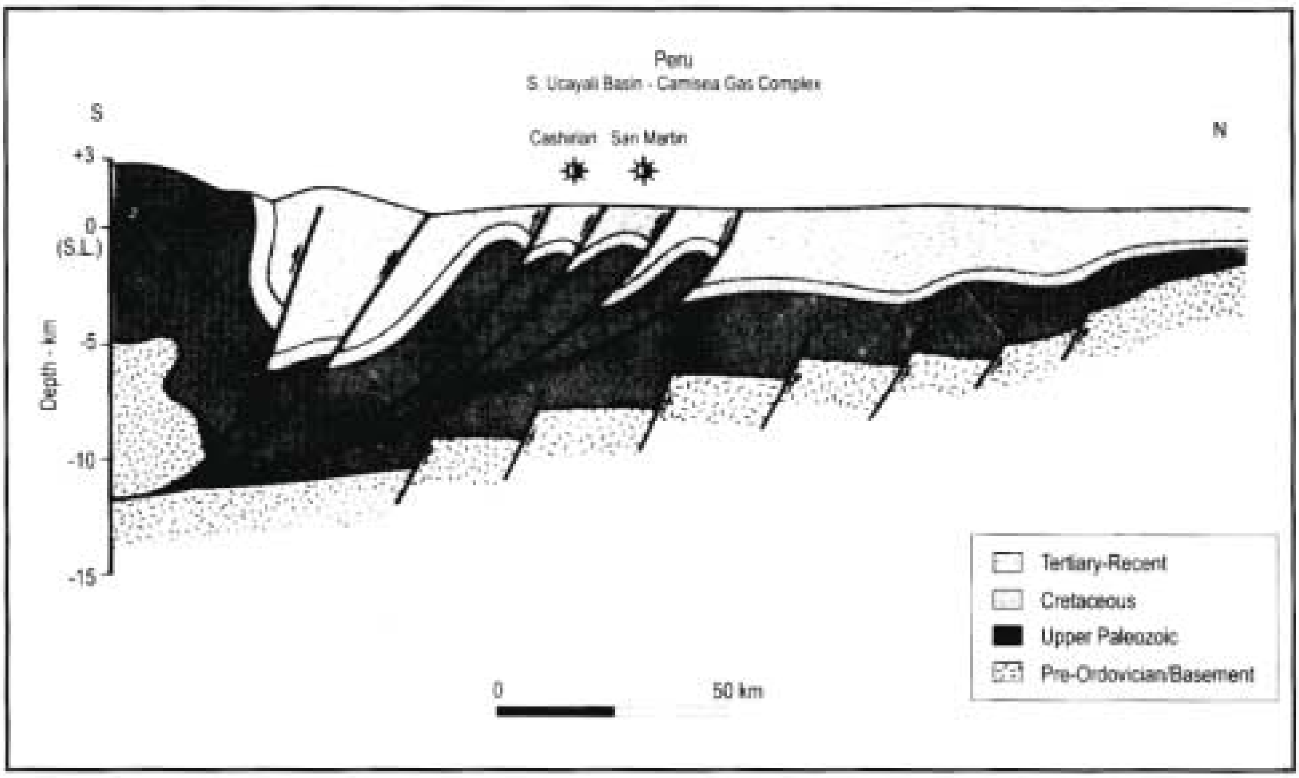


FIGURE 04 – Schematic regional cross-section of the southern Ucayali Basin, Peru, exhibiting the Camisea Gas Complex structural framework (modified after Mathalone and Montoya, 1995).

production tests also indicate a strong compartmentation of the structures, possibly by faults (strike-slip faults?) of less magnitude that are very difficult to define in seismic profiles. These barriers strongly affect the gas production capacity per well, and may result in heavy exploration and development costs due to the increase in the number of wells required to produce the same amount of gas.

The source of the Camisea Complex is still open to discussion.The existence of at least two potential source rocks in the basin is well known. The first are the Devonian marine shales of Cabanillas Formation that are comparable in terms of their thickness and areal extent to the Los Monos Formation of Argentina and Bolivia.The second are the shale and marlstone beds of Permo-Carboniferous age. The Permo-Carboniferous beds consist of deep-water and slope facies, very rich in algae-derived organic matter and time-equivalent to the high-energy platform carbonates of the Copacabana Formation. It may be that both source rocks were responsible for feeding gas and condensate to the huge structures of Camisea Complex.

Austral Rifts Petroleum Megasystem

The Austral Rifts petroleum megasystem occurs along the southernmost Andean margin in Argentina, and results from a major paleogeographic change in the southern part of the South American Continent. This change occurred during the earliest Mesozoic, and is associated with the shift of the magmatic arch westwards to a new position that approximates that of the present coast of Chile (Mpodozis and Ramos, 1989).

In this new plate tectonics scenario, a series of back-arc rift basin developed and remained active as typical extensional basins until the Middle Cretaceous, when a generalized tectonic event took place causing strong deformation in these basins. Amongst these back-arc rift basins are the Neuquén, San Jorge, Bolsones and Cuyo basins. The rock sequences in some of the basins were completely inverted during the Andean Orogeny, whereas others, mainly those in the E, were partially preserved (Fig. 5).

These rifts evolved from isolated deep fresh-water lakes to a more continuous gulf invaded by marine waters coming from the Pacific and filled up by siliciclastic sequences. In this geological context, thick pelitic units were deposited, providing excellent conditions for the preservation of organic matter, associated with deep lakes and relatively restricted marine conditions. The filling up of the basin led to the development of shallow water environments where fluvio-deltaic systems and carbonate platforms were installed resulting in the deposition of thick reservoir rocks, principally during the Late Cretaceous times.

Notwithstanding, that the original composition of the source rocks was more favourable for oil generation, they underwent deep burial in function of the volume of Andean cyclic sedimentation, reaching the gas window in most depocenters. Therefore, these basins have potential for both oil and gas. Typical examples of this petroleum megasystem may be found in the Neuquén Basin, mid-west Argentina.

Neuquén Basin

This basin has a triangular shape, covers an area of about 160 000 km^2 (Fig. 6), and, in like manner to all other austral rift basins, began as the result of an extensional episode in Late Triassic/Early Jurassic times with the

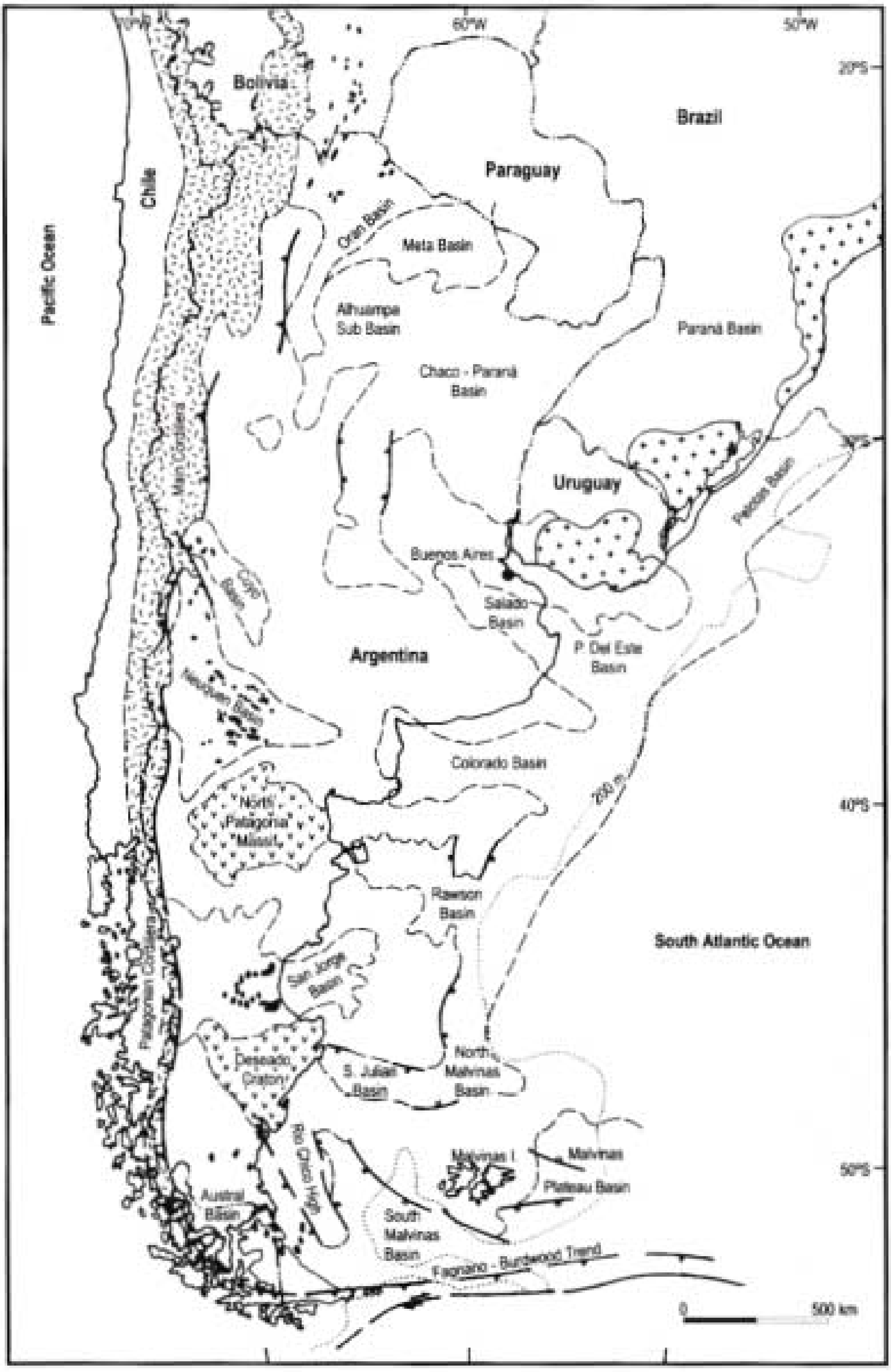


FIGURE 05 – Location map of the Austral Rifts Petroleum Megasystem, Argentina, displaying the main structural features, associated basins (Cuyo, Neuquén and San Jorge) and oil and gas fields.

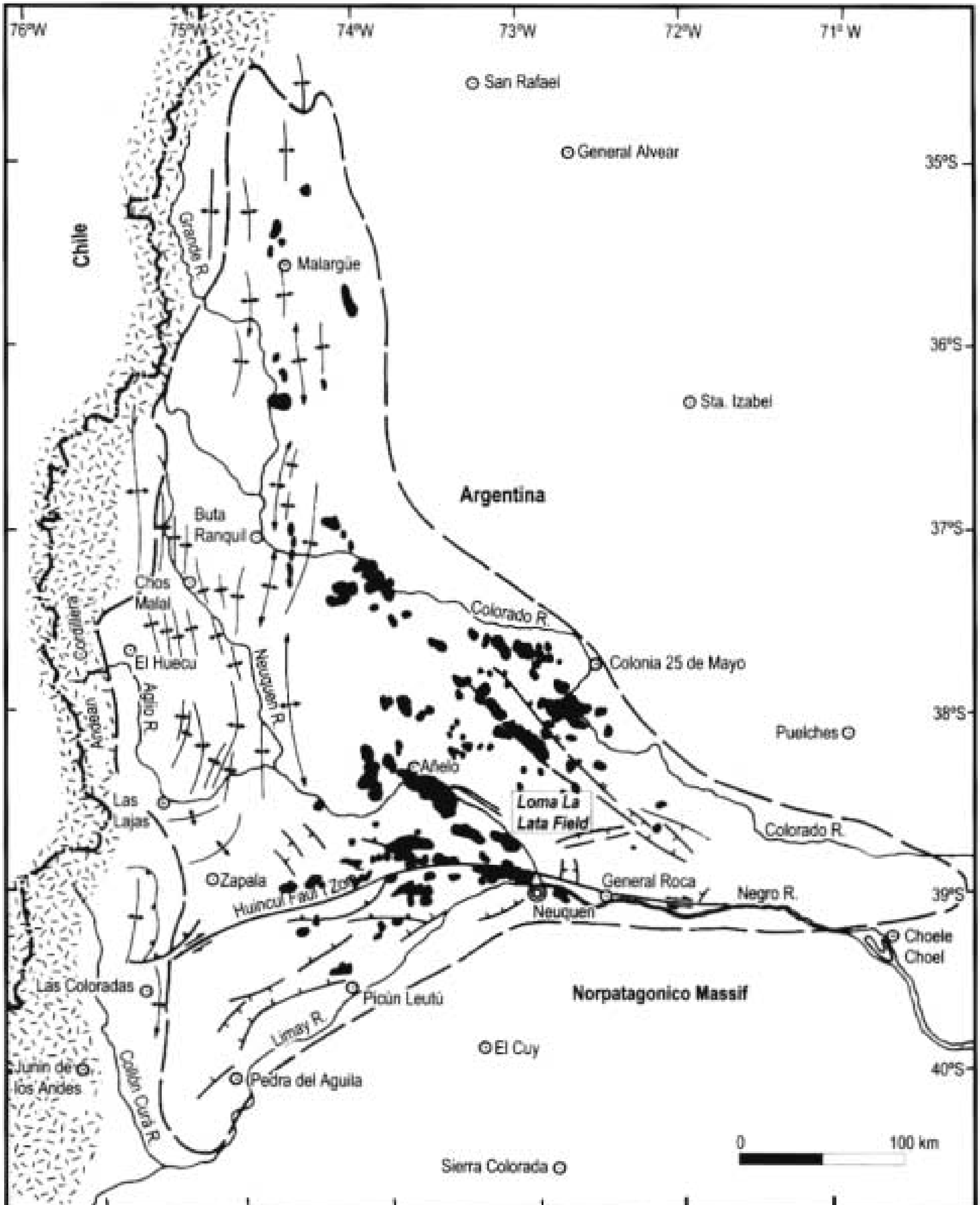


FIGURE 06 – Neuquén Basin map, Argentina, exhibiting the main structural features and oil and gas fields (modified after Legarreta et al., 1999).

widespread eruption of volcanic rocks. Following this event, shallow fresh-water lakes were developed in response to the stress field, since the connection with the Pacific was, at that time, limited by a submerged magmatic arch at the edge of the South American Plate (Legarreta *et al.*, 1999).

The shallow lakes evolved rapidly to deeper lakes with restricted circulation where dark shale beds with very high content of organic matter were deposited. Due to increasing aridity and evaporation, the salt content of the lakes reached the point that these became hypersaline. As a consequence of increased salinity, anoxic conditions developed and a permanent water stratification column was established giving rise to very favourable conditions for the preservation of the organic matter. The Puesto Kaufman Formation is representative of this rift stage, and may contain more than 2000 m of organic shale and coarse clastic sediments. The TOC content of this section varies from 2 to 8%, the hydrogen index is about 900 mgHC/g TOC, and the kerogen is type I, characterizing an excellent source rock.

The syn-rift isolated semi-grabens evolved to a more continuous basin (Gulf of Neuquén) that was invaded by normal marine Pacific salt water during the trangressive event associated with the Early Cretaceous rise in sea level. In this wider and shallower basin, a thick sequence of shale and marlstone beds was deposited, generating the best source rocks of the Neuquén Basin known as the Los Molles (Early Jurassic to Middle Jurassic) and the Vaca Muerta (Tithonian) formations. In the Los Molles Formation the TOC values are about 1 to 3%, with some intervals reaching 6%. The kerogen is of types I and II. The Vaca Muerta Formation consists of beds of bituminous marlstone and laminated shale. The TOC values of the Vaca Muerta Formation are around 2%, with peaks of 4%. The kerogen is of types I and II, and mainly derived from amorphous organic matter.

Besides these source rock sequences, there occur Hauterivian (Agrio Formation) sedimentary beds that are rich in organic material, also important as source rocks in some parts of the basin. The post-rift sedimentary sequence that fills the basin displays several transgressive-regressive cycles from the Jurassic to the Tertiary in response to the Andean tectonic pulses and sea level fluctuations. These cycles are limited by regional unconformities observed at the top of the Jurassic, in the Early Cretaceous (Kimmeridgian to Albian), and in the Late Cretaceous-Tertiary strata. These cycles are known as Rio Grandean and Andean cycles.

The stratigraphic column for these cycles consists of a very thick clastic wedge of continental origin at the base, covered by normal marine sediments. The marine beds change rapidly to those showing evidence for more arid and restricted marine and continental environments, including conditions favouring the accumulation of evaporite suites. Therefore an almost perfect association of source rock, reservoir and cap rock is present in most cycles. Linking this to the late basin structuration by the Andean Orogeny, and the creation of huge traps, this basin became highly favourable for hydrocarbon resources.

The Early Cretaceous cycle marks the maximum extent of the trangression when there occurred the deposition of abundant carbonate and marlstone beds as well as the sediments of the Vaca Muerta Formation, the main source rock. At the beginning of the Late Cretaceous, there started a new and very important tectonic pulse that was maintained during most of early Tertiary causing the deposition of a continental clastic wedge, subsequently covered by marine sediments. In the middle to late Tertiary there occurred the development of a pyroclastic complex that remained active until the Quaternary.

This basin displays a great variety of levels of reservoir-rocks throughout the stratigraphic column. Even the basal fractured and weathered volcanic Triassic rocks are hydrocarbon-bearing in some areas. However, the main reservoirs occur in the clastic sequences of the Punta Rosada, Tordillo, Mulichinco, and Agrio formations and the Neuquén Group.

The Punta Rosada Formation (Cuyo Group) reservoirs are representative of a marine marginal sequence consisting of fluvial and fan delta lobes having very good petrophysical properties. The Tordillo Formation reservoirs, also known as the Sierras Blancas Formation, consist of a thick sequence of coarse-grained fluvial-alluvial sandstone beds with provenance from the SE and SW that filled the basin and were subsequently buried by shale and marlstone of the Vaca Muerta Formation. During the Tithonian, shallow marine platforms were installed and thick carbonate and dolomite sequences were deposited. These sediments comprise the Loma Montosa Formation, and in some areas present very good reservoir properties due to intense dissolution and dolomitization.

At the top of the Vaca Muerta Formations there occur the clastic sediments of the Mulichinco Formation, deposited in fluvial, littoral and shallow marine environments. These beds are overlain by the clastic sediments of the Agrio Formation, consisting of eolian deposits displaying excellent reservoir qualities (Aviles Member).

During the Late Cretaceous, red beds of the Neuquén Group formed very thick deposits, mainly consisting of sandstone. The absence of significant pelitic intercalations may reflect the absence of commercial accumulations of hydrocarbons in these sediments; added to which there lacks an effective cap rock.

The very fine-grained shale and marlstone beds constitute the main cap rock beds in this basin, which are also responsible for the oil and gas generation. The evaporitic layers are present in the uppermost part of all the sedimentary cycles, acting as a very effective seal to hydrocarbon migration. The deposition of salt was mainly controlled by the dynamics of the magmatic arc in the western part of the basin. The tectonic movements of this arc were responsible for the large amount of water influx to the basin, and the establishment of a negative hydrological balance triggered the deposition of thick layers of anhydrite and halite. Subsequently, these plastic halite beds became very important as detachment zones for the propagation the Andean deformation throughout the basin, creating structural trends during the Cretaceous and Tertiary.

The several source rocks sequences, maturation and the main phase of oil expulsion and migration to the structural traps originated during the phase of Andean compression that started at the end of the Cretaceous. At present, the source rocks of the Vaca Muerta Formation have attained the initial phase of the gas window, whereas, the source beds of the Agrio Formation are still in the oil window. The older source beds of the basin are all in the gas window. This seems to explain why the Neuquén Basin contains such large volumes of oil and gas trapped within its fields.

The very intense tectonism developed at the end of the Cretaceous, and lasting throughout the Tertiary, oriented and controlled the initial migration of oil and gas in the basin. However, very important remigration must have taken place since the tectonic evolution gave origin to new hydrocarbon pathways along which the oil and gas was directed to newly-formed structures and/or combined traps associated with fractured reservoirs.

The main structural grain of the basin may be analyzed in two domains. The first domain is situated in the western part of the basin and was strongly affected by the Andean Orogeny, presenting very intense deformation and displaying faulted anticlinal trends. To the E of the volcanic arc, the deformation became more and more gentle and the structures are related to older basement faults and folds. Nevertheless, compression was the principal element by which structural trends were created in the basin, affecting not only the overall geometry of the basin, but also the facies changes and sandstone distribution. In this sense, the oil distribution is directly related to structural evolution of the basin.

The conspicuous Huincul Dorsal (Fig. 6) crosses the entire southern limb of the basin, and occurs as a very narrow deformation zone more than 200 km long. Along this zone, extensional and compression features are present, most of them *en echelon*, and interpreted as a huge transpression zone, active since the Jurassic. In this feature, several oil and gas fields were discovered, and a large volume of oil was trapped in very different types of trap. In the Neuquén Basin, most of hydrocarbons discovered are contained in 345 accumulations. The volume is estimated at 6.5 billion barrels of oil equivalent, a great part of which was found in combined traps. The Puesto Hernandez and Loma la Lata fields are very good examples of these types of accumulation. The Puesto Hernandez Field has an original oil recovery reserve of 620 million barrels, consisting mainly of good quality oil. The Loma la Lata Field has a reserve of 1.6 billion barrels of oil equivalent, composed essentially of gas. Steep dipping reservoir beds truncated by an important erosional unconformity and sealed by abrupt facies changes and permeability loss associated with the unconformity, are common features of both giant fields. Accordingly to Vergani *et al.* (1995) about 45% of Argentina's production comes from this basin.

Caribbean and Andean Foreland Petroleum Megasystem

In this megasystem are included almost all the petroleum occurrences along the transcurrent and foreland basins bordering the Caribbean coast in Venezuela and the Andean Chain of Colombia, Ecuador and northern Peru. These basins have in common the same rock sequence, deposited in a partially restricted marine environment from the Early to Middle Cretaceous, along the passive and mid-arc margin, developed along the northern and northwestern coast of South America.

Very favourable environmental conditions for generation and preservation of large amounts of organic matter were associated with the break-up of the South American and North American continents, originating a gulf known as Tethys Sea, a fore-runner of the present-day Gulf of Mexico. In this relatively shallow, warm and protected body of salt water that subsequently covered very large areas of the western margin of South America, reaching northern Peru (Cretaceous South American Seaway), thick sequences of shale and marlstone were deposited with a high content of algae-derived organic matter.

The Tethys Seaway is considered to represent the passive margin phase of a rifting process that took place in the area during the Triassic-Jurassic extensional event, similar to that responsible for the creation of the Austral Rifts. In this case the Tethyan Rift started its evolution in the Caribbean Region and propagated toward the S through Colombia, Ecuador, and northern Peru (Jaillard *et al.*, 1990).

At the end of Cretaceous and during the Tertiary this basin was submitted to the strong compressional effects of the Andean Orogeny (Daly, 1980). Subsequently, in the Neogene, the northern margin was also affected by the dextral shear stress field produced by the start of the Caribbean Plate motion. As a result of these complex geological events, the original basin, of enormous size, was divided into several segments by the uplift of regional arches, generating the present-day configuration.

In this megasystem the source rock sequence was essentially developed in a marine carbonate environment. These marlstone and shale beds, known by different lithostratigraphic names according to the specific basin in which they occur, include the Napo Formation in Ecuador; the Villeta and Gacheta formations in Colombia; and the La Luna and Querecual formations in Venezuela. All of these rocks have the same excellent characteristics of TOC content (higher than 5%), type I algae-derived kerogen and high hydrogen index, responsible for generating, where the thermal conditions have permitted, enormous amounts of liquid and gaseous hydrocarbons. To illustrate this petroleum megasystems some basins and giant oil fields will be described.

Oriente Basin

This basin (Figs. 3 and 7) covers an area exceeding 900 000 km^2, being known by different names in Colombia, Ecuador, Peru and Brazil: Putumayo, Napo, Marañon, Ucayali, Acre, Santiago, Huallaga and Ene basins. It contains several first-order sequences developed in a Silurian-Devonian back-arc basin, followed by those developed in another back-arc basin during the Permo-Carboniferous. In the Jurassic-Triassic it existed as a rift basin, and finally as a foreland basin during Cretaceous-Tertiary times.

In terms of the hydrocarbon potential, only the foreland basin is important as it contains both the source rocks and the reservoir rocks. The source rocks are marine marlstonestone and shale beds included in the Middle Cretaceous Napo/Villeta/Chonta formations, equivalent to the La Luna Formation in Venezuela. According to Carneiro and Cavalcanti (1994), the main depocenters where these

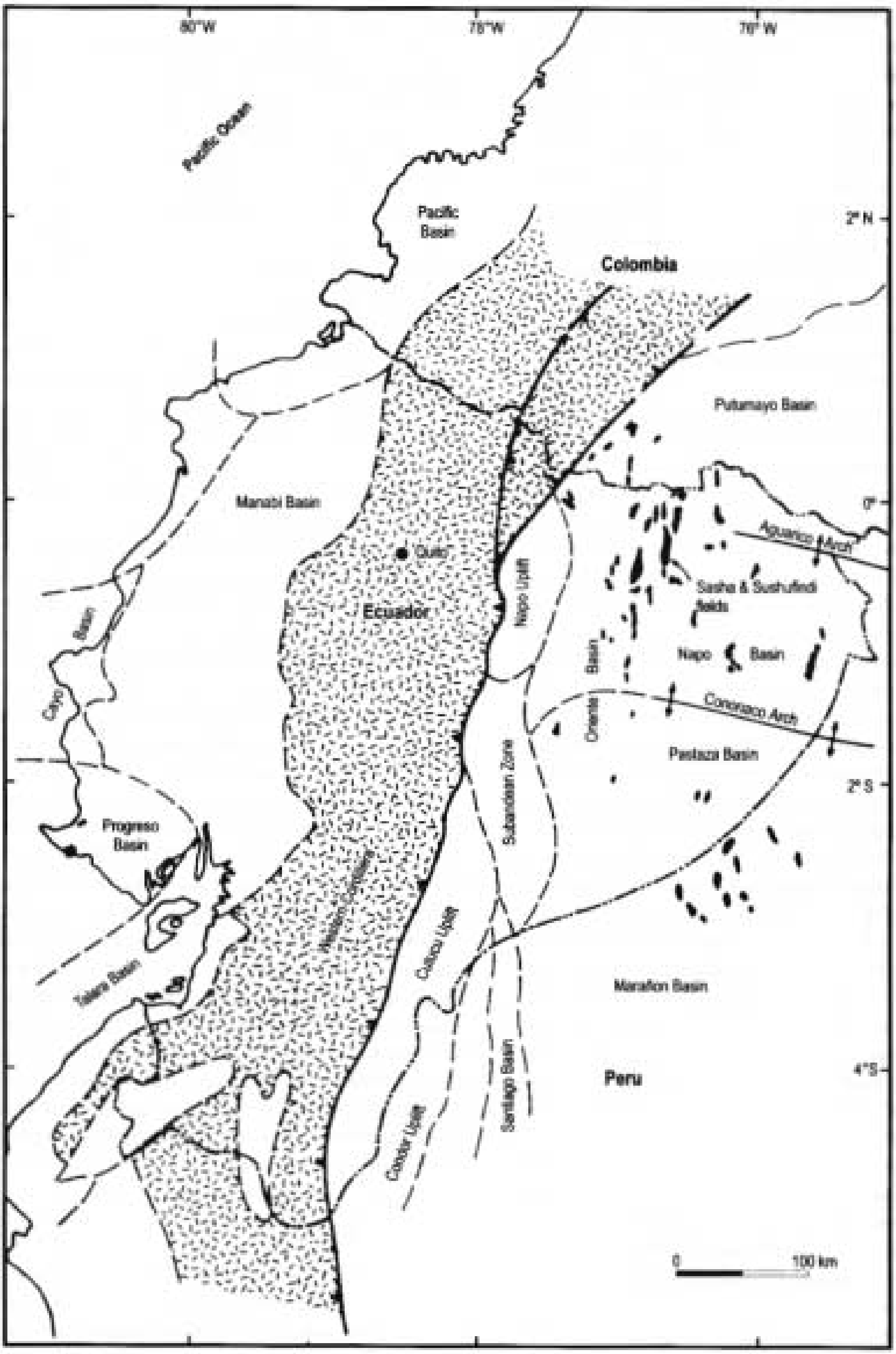


FIGURE 07 – Location map of the Oriente Basin (Marañon, Napo and Putumayo basins) of the Subandean Petroleum megasystem, in northern Peru, Ecuador and southern Colombia, displaying the main local features and oil and gas fields.

rocks attained the thermal conditions necessary to generate hydrocarbons are situated in the western part of Marañon Basin, Peru, very far from the main accumulation sites in northern Peru and Ecuador. Due to this fact, major secondary migration must have occurred over distances of some hundreds of kilometres.

The main reservoirs occur in the sandy units of the Hollin and Napo formations deposited in the Early and Middle Cretaceous. The Hollin reservoirs are also known as the Caballos and Cushabatay formations, the sediments of which comprise a regressive cycle associated with a generalized lowering of the sea level. The basal section consists of non-marine alluvial coarse-grained sandstone and conglomerate beds filling depressions and representing deposits characteristic of incised-valley channels. This sequence is covered by a very thick coarse to medium-grained sandstone unit associated with braided rivers. In some places eolian beds are developed at the top of this section.

This continental area of sedimentation was gradually inundated by a continuous sea level rise and covered by coastal sandstone deposits, strongly reworked by tides and waves, in addition to beds of marine shale and marlstone. The Hollin Formation lies at the base of the Cretaceous sequence throughout the entire basin, and attains a thickness exceeding 400 m in the depocenters.

The Napo Formation reservoirs are the least developed in terms of thickness and areal distribution, but still are present in most areas of the Oriente Basin. These reservoirs consist of sandstone intercalated with shale and marine carbonate units responsible for the oil generation. They were concentrated in three pulses of clastic input coming from the source area to the E where the granitic Brazilian Shield fed material to the basin. These clastic sedimentary pulses are known as the U, T and M sandstones or the Agua Caliente and Vivian formations, and were deposited during the progressive sea level rise and transgression of the Middle Cretaceous seaway during the Late Albian and Campanian.

They consist of deltaic and barrier-bar facies reworked by tides representing littoral, estuarine and shallow marine clastic deposits, developed over high-energy carbonate banks. This succession of deep-water marlstonestone and shale beds, carbonate bank deposits and clastics are interpreted to have formed as a consequence of tectonically-controlled third-order cyclic variations of the general trangressive sequence. Towards their source these three distinctive sequences grade laterally into a thick body of fluvial-alluvial sandstone units. This fact may explain the predominance of low API heavy and viscous oil in the accumulations of this basin, since a very intense process of fresh water invasion is present due to the existence of a very continuous carrier bed for the oil and water.

The main structural trends from where hydrocarbon production is obtained are related to folding and faulting resulting from the compression related to the Andean Orogeny. The oil is contained in relatively gentle anticlinal folds oriented N-S and associated with low angle thrust faults. The Late Cretaceous traps are usually filled with hydrocarbons, whereas the folds originated during the Tertiary are barren due to the absence of good cap rocks in the overlying continental beds of Tena-Tuyuyacu formations.

The uplift of the Andean Chain triggered the generation process only during the Neogene, when the source rocks present in the Napo Formation attained, in some depocenters, the thermal maturation conditions that were sufficient to expel the oil and gas to the Hollin and Napo reservoirs.

The presence of thick and laterally continuous sandstone beds in the Hollin and Napo formations, distributed over most of the basin permitted a good connection between the deeply buried reservoirs and the outcropping areas in both flanks of the basin. This is to say, the Brazilian Shield to the E, and the uplifted areas of the Andean Chain to the W. In consequence, massive fresh water percolation occurs in this basin, affecting directly the oil quality since a very active process of bacterial biodegradation is taking place in the accumulated oil. In this way most of the giant accumulations are to be found in the deeper parts of the basin, where this destructive process is less important, and where the reservoirs are more protected from water influx. The oil quality in these fields varies between 14° and 30° API. On the other hand, the presence of a regional aquifer in these reservoir rocks helps to maintain the pressure, allowing a very high recovery factor.

In Ecuador and northern Peru, the Oriente Basin has produced in the last 20 years more than five billion barrel of oil, from several oil fields including the giant Sushufindi and Sacha fields. Practically all of the remaining reserves in the basin, estimated at two billion barrels and the potential reserves are associated with this megasystem.

Llanos-Magdalena Basin

In Colombia, the Andean Chain is sub-divided into three branches and sedimentary basins are developed within these. The Eastern Cordillera consists of a sequence of rocks deposited from Jurassic and Early Cretaceous times, representing a rift phase that was covered subsequently by sediments related to a sag phase. In this phase Middle and Late Cretaceous marine beds and Tertiary continental sediments were deposited and subsequently deformed during the Andean Orogeny. The mountain building process of this orogeny permitted the preservation of large parts of the original basin, shaping lowland areas where large rivers came to be installed. Such rivers include the Madgalena and Cauca and their respective valleys.

In this context, the Magdalena Basin (Fig. 8) represents a large piece or relict of a huge ancestral basin deformed by the Andean Orogeny, comparable to the Oriente Basin in terms of its geological history, but completely deformed by the Andean compressional regime.

To the E of the uplifted Magdalena Basin and the Eastern Cordillera there occurs the almost undeformed part of this ancestral basin, preserved as a foreland basin and known as the Llanos Basin (Dengo and Covey, 1993), covering an area of about 200 000 km^2. The stratigraphic succession in both basins is very similar to that discussed above except that being closer to the source area of the Brazilian Shield the amount of clastic sediments is greater.

The first phase of the evolution of this basin compares with most others. However, in the Late Cretaceous and Tertiary strong and very consistent stress fields resulted in the development of a very large basin affected by folding, faulting and igneous activity. The evolution of the magmatic arc had ended by the Paleocene (Dengo and Covey, 1993).

The petroleum systems developed in this highly active tectonic environment were strongly controlled by tectonic evolution, seeing that the hydrocarbon generation and migration processes were strongly influenced by the thickening of the Middle Cretaceous shale beds, rich in organic material, and associated marlstonestone. Most of the oil accumulations are found in structural traps associated with regional thrust faults, low-angle reverse faults and Cretaceous and Tertiary detachment zones that propagated the compressional fronts throughout most of the basin.

In the foothills of the Llanos Basin of the Eastern Cordillera are found the most favourable sites for hydrocarbon accumulation, as shown by the presence of the giant fields of Cusiana and Cupiaga. In the less deformed areas, large fields such as the Caño Limon Field have been discovered. It is estimated that some 25 billion barrels of oil have been trapped in this basin.

In the Upper Magdalena Basin, oil and gas is being produced from the fluvial-alluvial sandstone beds of the Caballos Formation, time-equivalent to the Hollin Formation, as well as from the Monserrate and Guadalupe formations, consisting of fluvio-deltaic sediments of Late Cretaceous age. Representative fields of this basin are the San Francisco Field and the Dina-Tello fields, that originally contained reserves exceeding 400 million barrels of oil.

In the Middle Magdalena Basin, oil and gas were first discovered in Colombia. Nowadays there are about fifty producing oil and gas fields. The old La Cira-Infanta Field is a good representative of this oil system that originally contained about 800 million barrels of oil. In this type of accumulation, the reservoirs are found in the Tertiary sediments, consisting of sandstone and conglomerate, associated with fluvial and alluvial channel-fill environments (molasse sequence), with structural control by low-angle reverse faults.

The Cenomanian-Turonian marlstone and shale beds of marine origin provide all the hydrocarbons generated in these basins. These rocks are very rich in organic carbon derived from algae, presenting a very high conversion factor. They are included in the Villeta (Magdalena Basin) and Gacheta (Llanos Basin) formations, and are present in most areas of the basins, representing the continuation of the very same petroleum system present in Venezuela (La Luna Formation).

Cusiana and Cupiagua Fields

These fields were discovered at the end of the 1980s, and occur in the very highly deformed area in the transition zone between the Llanos Basin to the Eastern Cordillera. This area is known is the Llanos Foothills. In these fields, the traps form in very tight anticlines, associated with a basal detachment fault zone (Fig. 9). Hydrocarbon production comes from fluvio-deltaic and shallow marine sandstone units, assigned to the Guadalupe (Late Cretaceous), Barco and Mirador formations (Early Tertiary). This lies below 4000 m and locally below 5000 m.

The Guadalupe reservoirs were deposited when the relative fall of sea level permitted the deposition of two regressive-transgressive, third-order cycle sequences formed in fluvio-deltaic and offshore bars during the Coniacian and Santonian. The Barco and Mirador formations, deposited during the Paleocene and Eocene respectively, are the product of a regressive-transgressive sequence where channel-fill systems derived from the development of incised valleys were covered by transgressive estuarine sediments that rapidly evolved to a shallow sand-rich clastic platform where sand bars coalesced to form a continuous sandbody.

All of these reservoirs underwent very intense diagenesis due to the great depth of burial and the presence of tectonic conditions favourable to fluid circulation throughout the reservoir system. As a result of this process most of the reservoirs exhibit a very low porosity (normally below 10%) and permeability. However, the intense fracturing developed by several phases of tectonic activity, created a very complex system of fractures in these reservoirs, responsible for obtaining a very high production capacity; in some cases reaching values around 10 000 barrels/day per well.

The Cusiana reserves are estimated at 1.5 billion barrels of oil and 3.4 TCF of gas (2.1 barrel of oil equivalent). The Cupiagua Field was discovered later on in the same trend, but in an isolated anticline to the S (Fig.9). It contains about 500 million barrels of very light oil and condensate. Recently, some wells were drilled to investigate deeper pools in both anticlines, reaching depths exceeding 5800 m. These wells have found oil and gas in deeper reservoirs, still under evaluation, that may improve the reserves of these fields to around 3 billion barrels. The Cusiana Field came on stream recently and it is expected to reach the production peak of 500 000 barrels/day in the year 2000. To bring these fields into production it was necessary to construct a new oil pipe, crossing the very rough terrain of the Eastern Cordillera.

Caño Limon Field

The Caño Limon Field is shared by Colombia and Venezuela (Fig. 9). It was discovered in 1983, and covers and area of about 40 km^2. It continues to produces some 200 000 barrels/day of very good quality oil (30° API). The geology of this field is quite different to that of the Cusiana Field. It is situated in an area where the Andean Orogeny produced only gentle folds and minor faults. Due to this fact, the oil is trapped in an area of low relief and in a broad anticline, controlled by the motion of transcurrent faults active during the late Eocene and Oligocene. The lateral displacement of these faults is believed to be between 2 and 4 km (McCollough and Carver, 1990).

Deltaic sandstone pertaining to the Mirador Formation, with about 80% of the total reserve constitutes the main reservoir rocks of this field. These reservoirs are buried at a depth of 2200 m, and have an average porosity of around 25% and permeability greater than 1 Darcy. In function of these very favourable petrophysical properties, the capacity of production exceeds 20 000 barrels/day of oil per well. The low gas-oil ratio of this field is very effectively compensated by a strong and very active aquifer. The highly efficient water drive mechanism has permitted a very high recovery factor of about 60% over an original reserve estimated at 1.8 billion barrels of oil.

Maracaibo Basin

The Maracaibo Basin, in the northeastern Venezuela, covers an area of about 50 000 km^2, and has resulted from

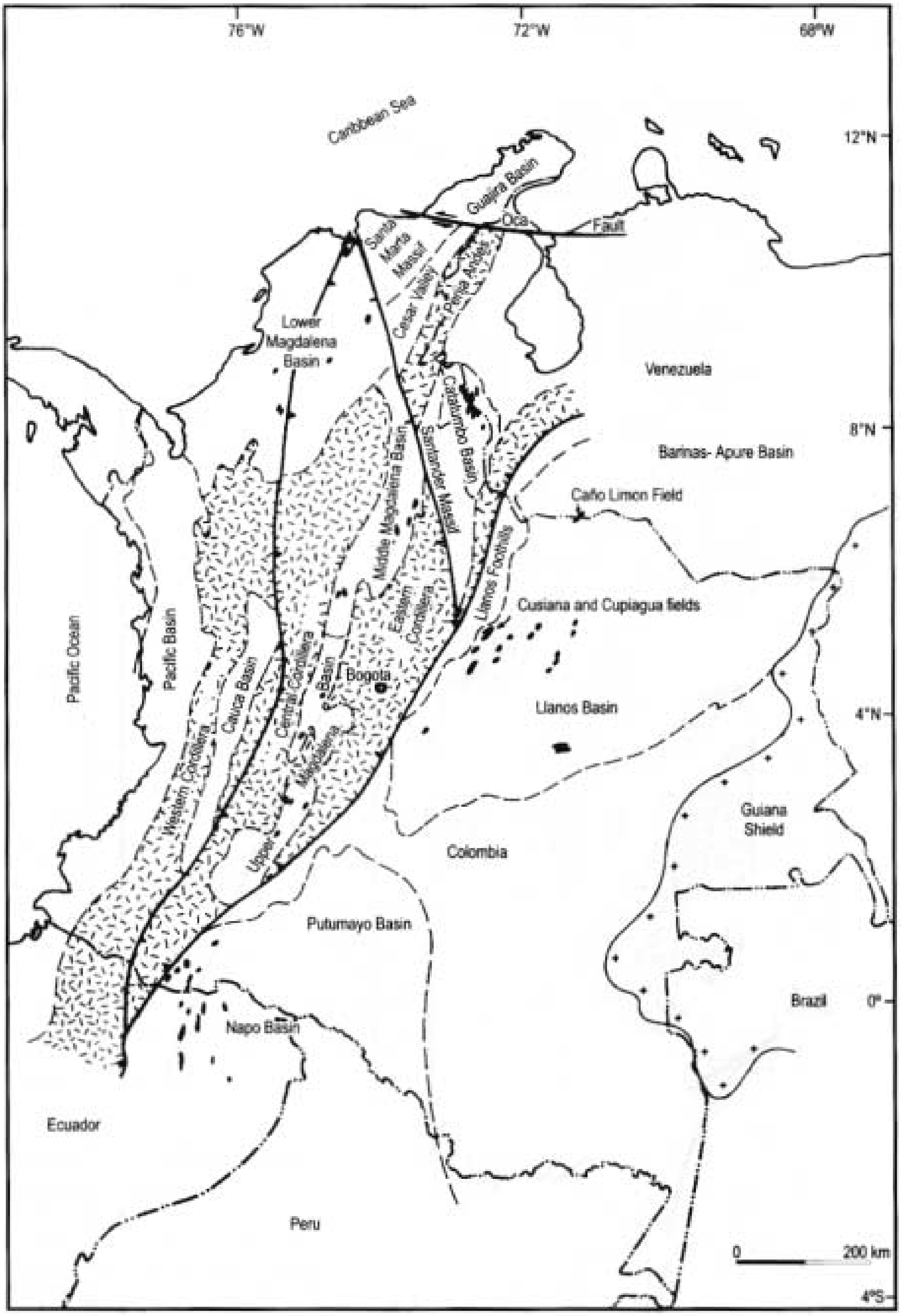


FIGURE 08 – Location map of northern portion of the Andean Foreland Petroleum Megasystem, Colombia, showing the main structural features, associated basins and oil and gas fields

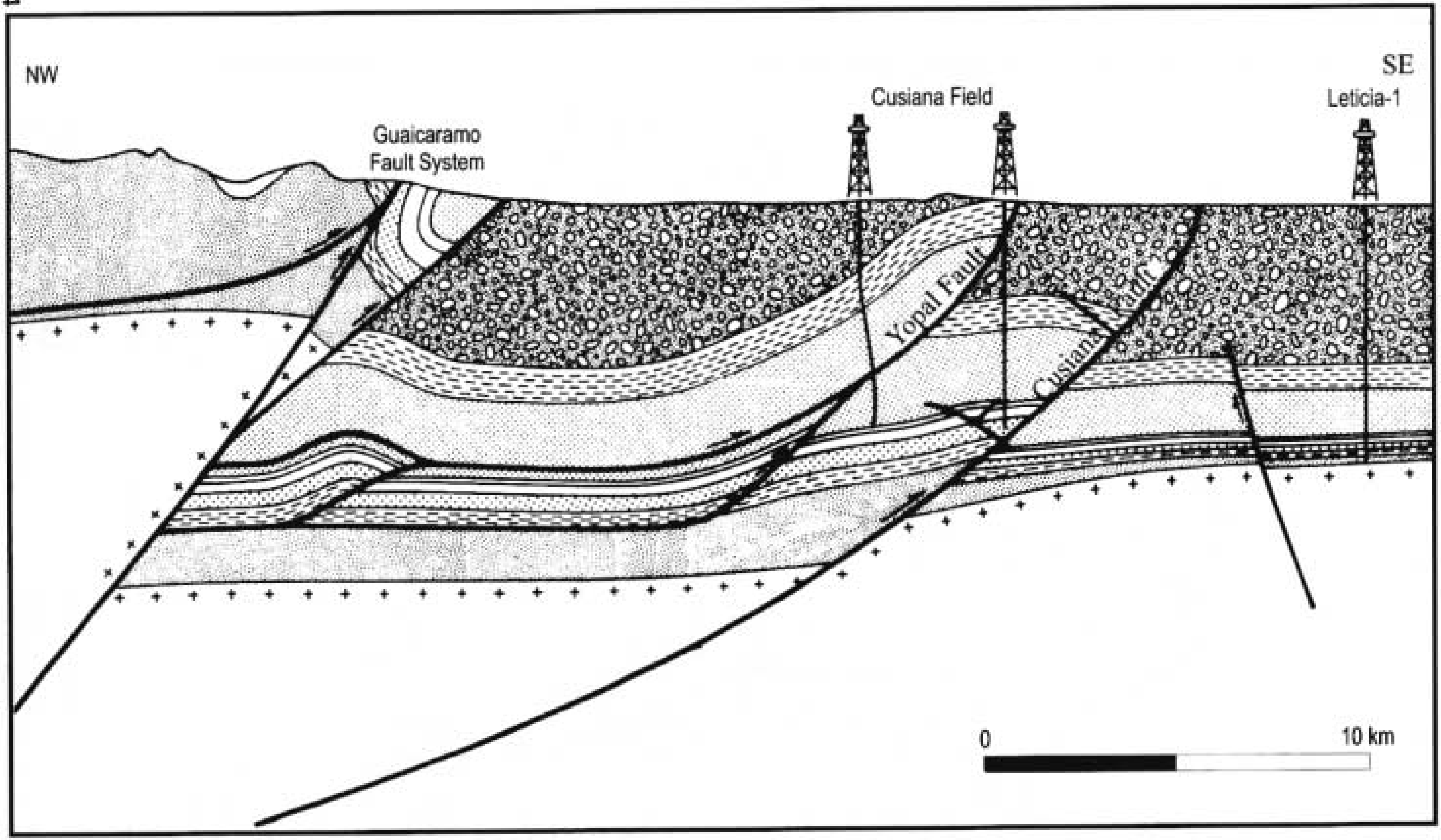


FIGURE 09 – Schematic regional cross section across the Llanos Basin, Colombia showing the Cusiana Field structural framework (modified after Cooper et al., 1995). No vertical scale.

the very complex interaction and collision of three plates: the Nazca, Caribbean and South America plates. Since the Early Paleozoic this basin has evolved from a back-arc basin, passing through a rift phase in the Jurassic; a passive margin phase during the Cretaceous and attained a foreland phase during the Paleogene (Lugo and Mann, 1995). Its present-day configuration is controlled by the Mérida Andean Chain to the E, and by the Sierra de Perijá to the W, as well as the megasuture represented by the Oca, Perijá and Boconó transcurrent fault system to the N (Fig. 10).

In the last fifty years the Maracaibo Basin has produced around 35 billion barrels of light to medium quality oil, and the remaining reserves are estimated in about ten billion barrels of oil. This type of oil accounts for almost 50% of the Venezuelan reserve. The petroleum resources of this basin are entirely related to a fault system formed by parallel transcurrent faults with sinistral motion, striking approximately N-S. This system originated by the introduction of the Caribbean Plate during the Neogene, and most of the giant accumulations such as Mene Grande, Bacachero, Lagunillas and Ceuta-Tomoporo fields, are aligned along the western margin of Lake Maracaibo, and are controlled by this tectonic event. These fields are collectively known as the Bolivar Coastal Fields (Fig.10).

The marlstonestone, shale and fine-grained carbonate beds of the La Luna Formation have a very high content of algae-derived amorphous organic matter, being the source rock of this huge amount of hydrocarbon. These rocks were deposited during the Cenomanian-Turonian anoxic event and are related to a period of maximum flooding that can be correlated worldwide.

Samples collected from immature areas have an average TOC content of about 5%, and it is estimated that around 290 million barrels of oil may be produced from each cubic kilometre of source rock (Ramírez and Marcano, 1990). This means that if the entire area that attained the required thermal conditions to produce hydrocarbons is taken into account, then the La Luna Formation may have generated more than one trillion barrels of oil to feed the traps in the Maracaibo Basin.

Bolivar Coastal Fields

This group of giant petroleum fields was discovered shortly after oil exploration in Venezuela began. Here, exploration was oriented by the presence of abundant oil seepages along the coastal areas of Lake Maracaibo. These accumulations are found in structures following a N-S trend for more than 70 km along the eastern margin of the lake and may reach until 30 km of width in lake waters (Fig. 10).

The productive section occur in Eocene deltaic sandstone beds (Trujillo and Misoa formations) and in Miocene coarser clastics of fluvial origin (Lagunillas Formation). These depositional systems were controlled by a foreland tectonic environment (Lugo and Mann, 1995). The entire sequence formed by successive intercalations of shale and sand may reach a total thickness of about 10 000 m in the main depocenter, located in the foothills of the Mérida Andes.

The trapping mechanism responsible for the huge amount of hydrocarbons is closely associated with transcurrent faults and folds related to the oblique collision of the Caribbean Plate against the South American Plate, that occurred throughout the Late Tertiary. Combined and stratigraphic traps are also present, some of them having as the top seal asphalt lakes derived from seepage and biodegradation of the oil.

More than 200 different accumulations have been found in this area, at depths varying from 170 m to 3000 m, containing oil that varies from 12° to 43° API. In the light of recent technological advances, such as 3D seismic data acquisition and processing, sequence-stratigraphy analysis, reservoir delineation and multi-lateral and horizontal drilling technologies there has been a significant increase in the recovery factor of these huge accumulations. The application of new technology to seismic surveying has brought about a boom in the exploration of deep targets including those in fractured Cretaceous carbonate of the La Luna Formation, at depths of between 4000 and 6000 m. The production mechanism usually present in these accumulations is water drive associated with gas dissolution, allowing very good recovery factors.

Maturín Basin

The Maturín Basin is part of the Eastern Venezuela Basin and is the second oil producer in this country, being active in oil exploration since the beginning of this century (Fig. 10). The basin is limited to the N by the Serrania del Interior range formed by a belt of folded and faulted rocks produced by the oblique collision of the Caribbean Plate along the El Pilar Trancurrent Zone, and to the S by the granitic terrane of the Guiana Shield.

The oil exploration began in this basin at the end of the XIX century, due to the presence of very large seepage areas occurring close to the foothills of the mountains. Commercial production began in 1913, when some very shallow oil occurrences were discovered in Tertiary reservoirs (Aymard *et al.*, 1990). In the last eighty years this basin has produced more than 1.8 billion barrels of oil (Prieto and Valdes, 1990), mainly from these shallow reservoirs. In the last fifteen years, exploration using more advanced technology resulted in the discovery of a few giant oil fields in deep reservoirs. Amongst these accumulations there may be cited the El Furrial Field, discovered in 1984 in reservoirs at a depth of 4500 m (Fig. 11).

The source rock sequence of the Maturín Basin has the same characteristics as the La Luna Formation of the Maracaibo Basin, but in the Maturín Basin these are known as the Querecual and San Antonio formations. These rocks were deposited in a bathyal marine anoxic environment, responsible for the accumulation and preservation of huge amounts of algae-derived organic matter. Recent quantitative geochemical studies indicated TOC content varying between 2% and 6%, and a potential of 56 to 252 million barrels of oil per cubic kilometre of mature rock. Therefore, taking into account the area of occurrence of this sequence, and assuming the required thermal conditions throughout, a resource exceeding two trillion barrels of oil in this basin can be estimated.

Along the southern border of the basin there occurs a very large belt of heavy oil as the result of a massive up-dip migration of oil from the deeper parts of the basin through the very permeable Tertiary reservoirs toward its outcrop areas. This belt, known as Orinoco Heavy Oil Belt, contains an estimated volume of heavy oil of about one trillion barrels (Fig. 10). The oil is stored in reservoirs with porosity values over 30% of the Las Piedras, Oficina and Merecure formations (Oligocene to Pliocene). This accumulation is sealed at the surface or at a shallow depth by asphalt lakes that have formed due to the biodegradation of the crude oil by bacterial action.

El Furrial Field

This field is situated in the tectonic domain of the Serrania del Interior range, consisting of a very complex reverse fault and fold system. The trap is an anticline associated with a very large thrust fault. It has an area of about 80 km^2, and vertical closure of around 900 m (Fig. 11). The main reservoir of the El Furrial Field lies below 4000 m, but it still has very good petrophysical properties including an average porosity of 15%. The reservoir rocks consist of deltaic and estuarine sandstone deposited as offshore bars and barriers bars during the relative lowering of the sea level during the Oligocene. The net pay zone occurring within the Naricual Formation is 276 m thick. In addition to these reservoirs there occur important production zones in the deeper parts of Late Cretaceous deposits.

The source rocks of the El Furrial Field are contained in the above-cited Querecual and San Antonio formations, buried deep below the Serrania del Interior. Here these rocks attained conditions favourable for the generation of huge volumes of mature and light oil and gas expelled to the shallow parts of the basin from the Miocene to the present-day.

El Furrial Field reservoir yields a good quality oil, around 29°API, and the production wells may yield over 12 000 barrels/day each. The fields do not have any oil-water contact and the main production mechanism is the pressure solution and fluid expansion in the reservoir. Because of this, a project of water injection was implemented in order to maintain the reservoir pressure to sustain the production level at about 380 000 barrels/day. The original *in situ* reserve is estimated at 6.8 billion barrels, and the remaining reserve is around 2.6 billion barrels.

South Atlantic Rift Petroleum Megasystem

In this megasystem are included a very large number of basins developed along the margin of the South Atlantic, off the coasts of Argentina, Uruguay and Brazil. All these basins have a common genesis linked to the continental break-up and drift of South America and Africa since the Late Jurassic. Continental break-up resulted in the generation of a series of linked rift basins which evolved to a restricted seaway or proto-gulf and, in most cases this opened up to create fully interconnecting marine passive margin basins, resulting in the present-day South Atlantic Ocean (Chang *et al.*, 1992).

Evolutionary events resulted in the deposition of two very important source rock sequences that are responsible for most of the oil and gas found in these basins. The older beds consist of continental shale deposited in a lacustrine environment. These lacustrine sediments may have been deposited in initially shallow depressions associated with the first phases of distension and rift formation, or related to half-graben development during the taphrogenic phase of rift evolution, when anoxic deep lakes were formed. Furthermore, the chemistry of the lake waters may have varied from fresh, as in the Recôncavo Basin, Brazil; or brackish to salty, such as in the Campos and Austral basins, in Brazil and Argentina, respectively.

The younger source rock sequence is related to the development of a proto-gulf or marine seaway at the end of the rift phase (Barremian to Aptian), when the half-grabens and shallow platforms where invaded by the sea water, interconnecting most of the basins and developing a relatively narrow seaway. This proto-gulf was 5000 km long and relatively shallow, extending from the Austral Basin off Argentina to the Sergipe-Alagoas Basin off northeastern Brazil. In this seaway, the Brazilian waters became progressively hypersaline due to the presence of a volcanic barrier situated in the present-day northern Pelotas Basin. These restricted conditions were highly favourable for the preservation of a thick sequence of black shale beds associated with a marine evaporitic suite. As a consequence, a very extensive and thick sequence of rocks with high organic matter content was deposited almost along the entire length of the South Atlantic margin of Brazil.

In this megasystem the oil derived from one of the above mentioned source rock or from both petroleum sub-systems migrated to traps and reservoirs during the rift, marine-evaporitic and passive margin sequences. Thus, giant oil accumulations developed in clastic reservoirs deposited immediately below or above the source rocks, or in reservoirs deposited during the Late Cretaceous and Tertiary and situated up to some kilometres above the source rocks. Vertical secondary migration is proposed to explain this fact, and very effective salt tectonics have played an important role in the development of this petroleum sub-systems. The Austral, Recôncavo and Campos basins have sub-systems that serve to illustrate the megasystem.

Austral Basin

The Austral Basin, also known as the Magallanes Basin, is situated in the extreme S of the South American Plate. It is limited to the W by the Andean Cordillera, and extends out into the Argentinean Atlantic Ocean as far as the Rio Chico High (Fig. 5). It covers an area of about 170 000 km^2 of which almost 23 000 km^2 are on the continental platform.

This basin developed during two distinctive rift phases in the Middle and Late Jurassic, respectively, and terminated with the extrusion of a very thick sequence of volcanic material known as the Tobífera Series of Early Jurassic age. In this phase the crustal opening diminished in intensity, and the basin was covered by continental clastics, filling shallow depressions associated with half-grabens. Following this terminal rift phase, a sag phase occurred during the Early Cretaceous, and typical transgressive sequences were deposited, known as the Springhill Formation, during the Early Valangian and Hauterivian. In Middle and Late Cretaceous the Austral Basin evolved to a special or discrete type of foreland basin, in part associated with the Patagonian and Andean tectonism (Robinnno *et al.*, 1996).

In this basin, the source rocks in the Early Cretaceous

FIGURE 10 – Location Map of the Caribbean Foreland Petroleum Megasystem, Venezuela, showing the main structural features, associated basins and oil and gas fields.

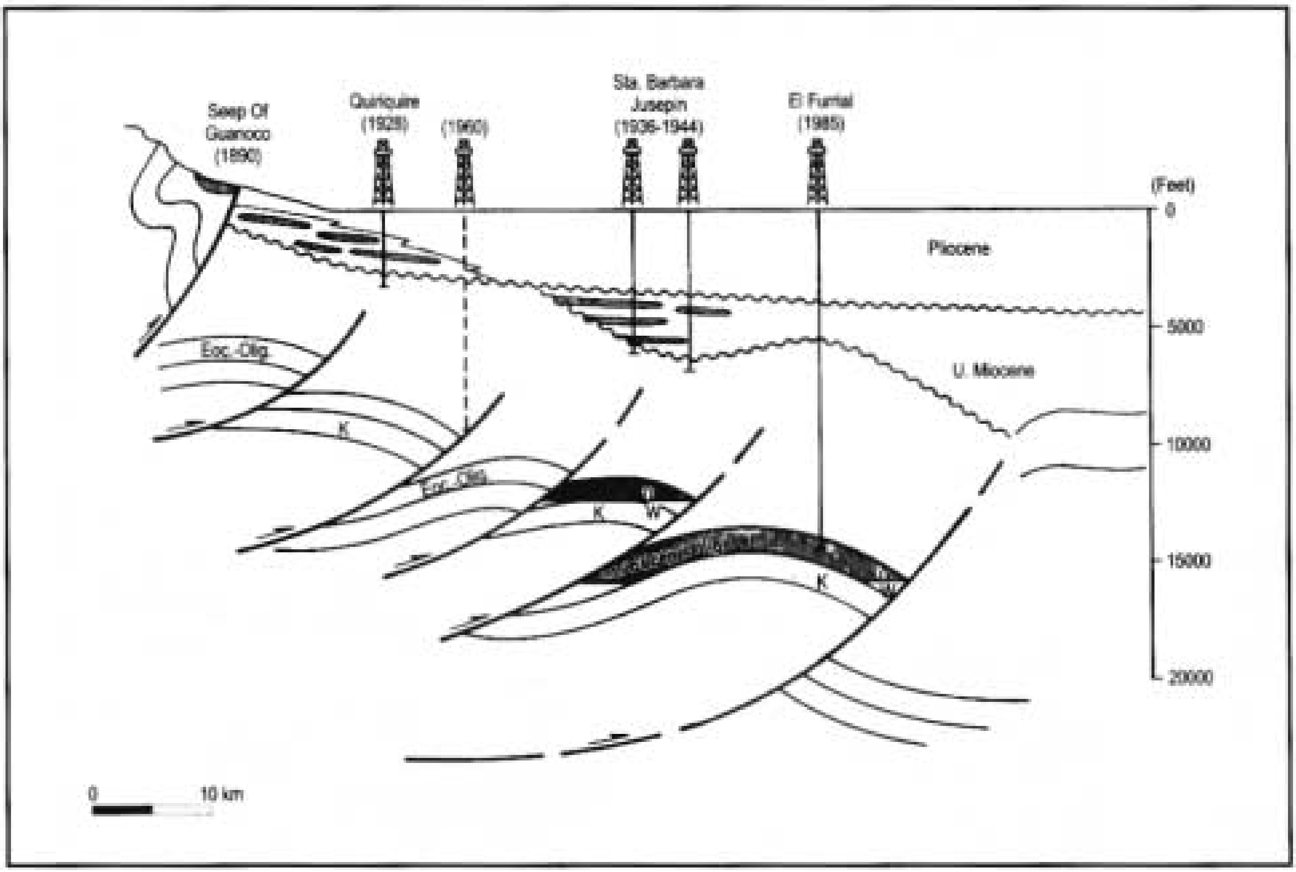


FIGURE 11 – Schematic regional cross-section across de Maturin Sub-basin, Venezuela, showing the El Furrial Field structural framework (modified after Prieto and Valdés, 1990).

sedimentary section (*Inoceramus*/Springhill formations), where basal continental shale beds that grade to beds of marine marlstone and shale with encroachment of the sea. As a result, most of the source rocks show a strong continental contribution and influence, and the organic matter present in these rocks has a mixed origin.

In the western part of the basin these rocks are deeply buried and display thermal conditions favourable for the production of gas. On account of this, the resources found in this basin are composed of 70% gas and 30% mature oil. The fluvial and shallow marine sandstone units of the Springhill Formation form the main reservoirs of this basin. The source rocks directly cover these reservoirs, and in this sense only a very short vertical distance was required to introduce the oil and gas.

Structural or combined features constitute most of traps present in the basin. Normal faulted blocks associated with the final phase of rift evolution produced the structural features and the combined features were associated with the onlap of the coastal sandstone beds, deposited during a regressive phase. During the Tertiary, the basin was affected by extensional and transpressive movements originated by the Andean Orogeny, forming small faulted blocks and pull-apart basins of little economic interest.

A conspicuous characteristic of this basin is the very large lateral migration. As previously stated, the source rock covers an excellent carrier bed (Springhill Formation reservoirs) and itself was acting as a very effective seal. This combination allowed the oil to migrate a very long distance, charging the existent traps or reaching the surface. Pittion and Arbe (1997) studies indicated that, in some areas, oil migration reached about 200 km.

Only a small number of hydrocarbon accumulations found in the basin were developed, since most of the discovers made were gas pools, some with an oil ring at the base. The Hidra Field has produced around 46 million barrels of oil. The gas is sold in Buenos Aires. The proven gas reserves already found and certified in the Austral Basin exceed 100 billion cubic metres.

Recôncavo Basin

This basin is situated in northeastern Brazil and occupies an area of 11 500 km^2 in the State of Bahia. In a regional tectonic context this basin represents the southern part of an aulacogen developed from a triple junction situated in the position of the City of Salvador. This branch of an aborted rift was isolated at the end of the Cretaceous from the other two branches that gave origin to the Atlantic Ocean (Fig.12).

According to Szatmari *et al.* (1985), the Late Jurassic-Early Cretaceous stress field, influenced by pre-existing weakness zones in the basement, created a small crustal block known as East Brazilian Microplate (EBM). The independent counterclockwise movement of this microplate in relation to the nascent South American Plate permitted the development of an intracontinental rift in this area. In the Aptian, the movement of the microplate ceased and, as

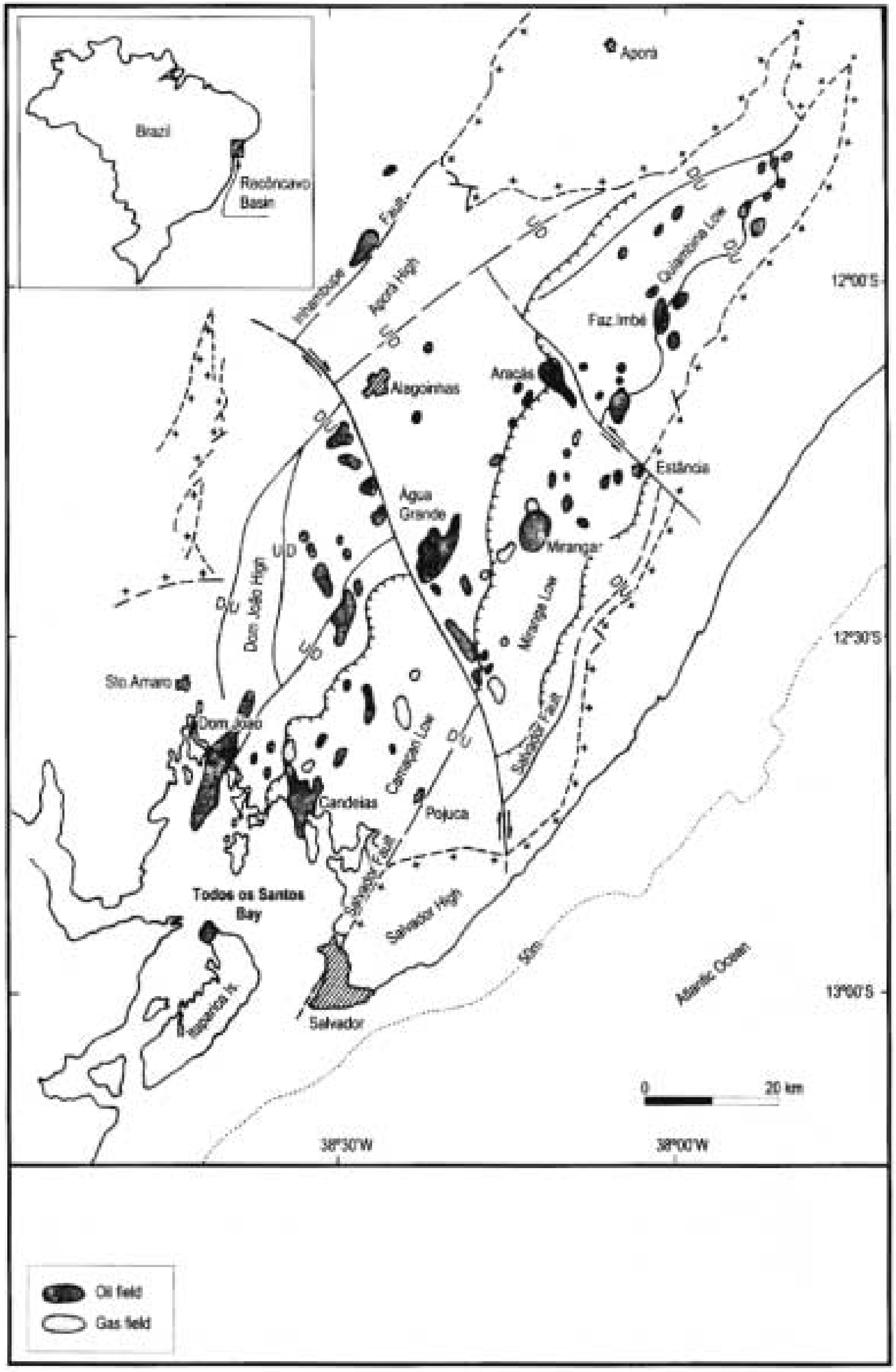


FIGURE 12 – Recôncavo Basin map, onshore northeast Brazil, showing the main structural features and oil and gas fields (modified after Figueiredo et al., 1994).

a consequence, the interior rift branch was abandoned.

In the Recôncavo Basin the main source rocks are fresh water lacustrine shale beds. When the rift evolution started there developed shallow lakes in a depression formed by the gentle extension of the crust, resulting in the generation of extensive argillaceous deposits with organic matter that covered almost all the basin. Subsequently, with the paroxysm of the rifting event, very deep (1000 m) lakes were formed (half-grabens) and a thick sequence of shale beds, rich in organic matter, was deposited and preserved in anoxic conditions confined to these depocenters. The first type of source rock is found in the Tauá Formation; whereas, the second is contained in the Gomo Formation.

Both source rock-types have an average organic matter content (TOC) below 2%, and residual generation potential between 5 and 10 kg HC/ton of rock. These relatively low values are interpreted as being related to the very high convertibility of the original organic matter into hydrocarbons, already expelled to the traps.

The main reservoirs of the basin are found in the pre-rift section (Late Jurassic) and in the syn-rift section (Early Cretaceous). The pre-rift reservoirs consist of alluvial-fluvial sandstone of the Sergi and Água Grande formations that floor most of the basin and have a uniform thickness of about 150 m. Overlying these sands there occur well-developed eolian beds presenting favourable petrophysical properties as reservoir-rocks.

The syn-rift reservoirs are distributed along the entire section of the basin fill. In the main depocenters the deep lakes were totally filled by a package of shale beds (source rocks) and sandy sediments. These sediments were deposited by high and low-density density turbidity currents, locally presenting good reservoir quality (Candeias/Maracangalha formations). During this phase, the tectonic control over deposition prevailed, and in the active eastern border conglomerate units were stacked resulting in the deposition of a wedge, locally up to 2000 m thick (Salvador Formation).

Following this first tectonic pulse there occurred a more quiescent phase. The progressive filling of the basin permitted the rapid advance of sand-rich fluvio-deltaic fronts over the shallow basin, responsible for the development of laterally continuous reservoirs during the syn-rift phase (Marfim/Pojuca formations and Catu Member). During the final phase of rifting, the basin subsided slowly and was filled by coarse-grained sandstone and shale beds with a very high sand/shale ratio, deposited under fluvial conditions (São Sebastião Formation).

The main trappping mechanisms in this rift basin are related to faulted blocks. These structures are related to basement-involved normal faults affecting the pre-rift and syn-rift sediments by the development of horst and block-faults. They may also be related to the development of shale diapirs and listric normal faults detached in the Candeias Formation, with associated rollover anticlines, affecting only the syn-rift section. Associated with the depocenters, and controlled by the half-graben, there also occur combined and stratigraphic traps, affecting mainly the reservoirs formed by turbidite beds.

For more than sixty years the Recôncavo Basin has produced more than 6 billion barrels of very good quality waxy and paraffin-rich oil (30° to 40° API) and more than 100 billion cubic metres of gas. Remaining reserves are estimated at about 300 million barrels of oil and 44 billion cubic metres of gas.

Campos Basin

The Campos Basin is situated on the offshore part of the State of Rio de Janeiro, southeastern Brazil, close to the state capital of Rio de Janeiro (Fig. 13). The Campos Basin is the most productive oil basin along the entire American side of the Atlantic Ocean, and it contain about 80% of the oil found and produced in Brazil. The basin covers an area of about 100 000 km² extending from the coastline to the 3000 m isobath. It is limited to the N and to S by shallow water basement highs separating the basin from the Espírito Santo Basin and Santos Basin, respectively. Both these basins are oil and gas producers. In the deep water domain there is no physical separation among these basins.

This basin is an excellent representative of the so-called Atlantic passive margin basins, present along the eastern coast of South America and western coast of Africa. The basin has developed on an extrusive volcanic substratum that resulted from the final phase of the break-up of Pangea (Cabiúnas Formation). This unit is present all over the southern submarine part of South America and extends inland over the Paraná Basin where the basalt sheets may exceed 2000m (Serra Geral Formation).

The evolution of the basin started with a rifting episode in the Early Cretaceous, causing the development of relatively shallow half-grabens where continental lacustrine sediments were deposited in fresh to brackish water. These lacustrine sediments consist of coarse-grained basal conglomerate containing basalt fragments, overlain by fine-grained siliciclastic sediments deposited in an alkaline environment. These siliciclastic sediments include talc-stevensite mudstone with very high organic matter content (Lagoa Feia Formation). Also present in this thick rift sequence are carbonate banks built of pelecypod and ostracod shells (coquina).

In the Barremian to Aptian transition, a strong erosional angular unconformity peneplained the basin, and over this flat surface there occurred the first marine transgression from the S. Once a more continuous water body along the Brazilian continental margin (proto-gulf or seaway) had developed, the prevalent arid conditions and the presence of a barrier to the S permitted the deposition of a thick sequence of evaporite beds. These evaporite beds consist mainly of cyclic deposits of halite and anhydrite and, in the present day deep waters of Santos and Campos basins, is estimated the existence of an original thickness of almost 2000 meters of halite (Retiro Member).

Continuous plate drifting and deepening due to active thermal subsidence enlarged the seaway. During the Albian, an extensive ramp-type carbonate platform, more than 600 m thick, developed in the shallower areas. This ramp consists mainly of grainstone (oolitic and pisolitic banks) grading to mudstone and marlstonestone in the deeper parts. During the Cenomanian to the Campanian times this high energy carbonate ramp was flooded by a continuous sea level rise and deep-water carbonate facies and

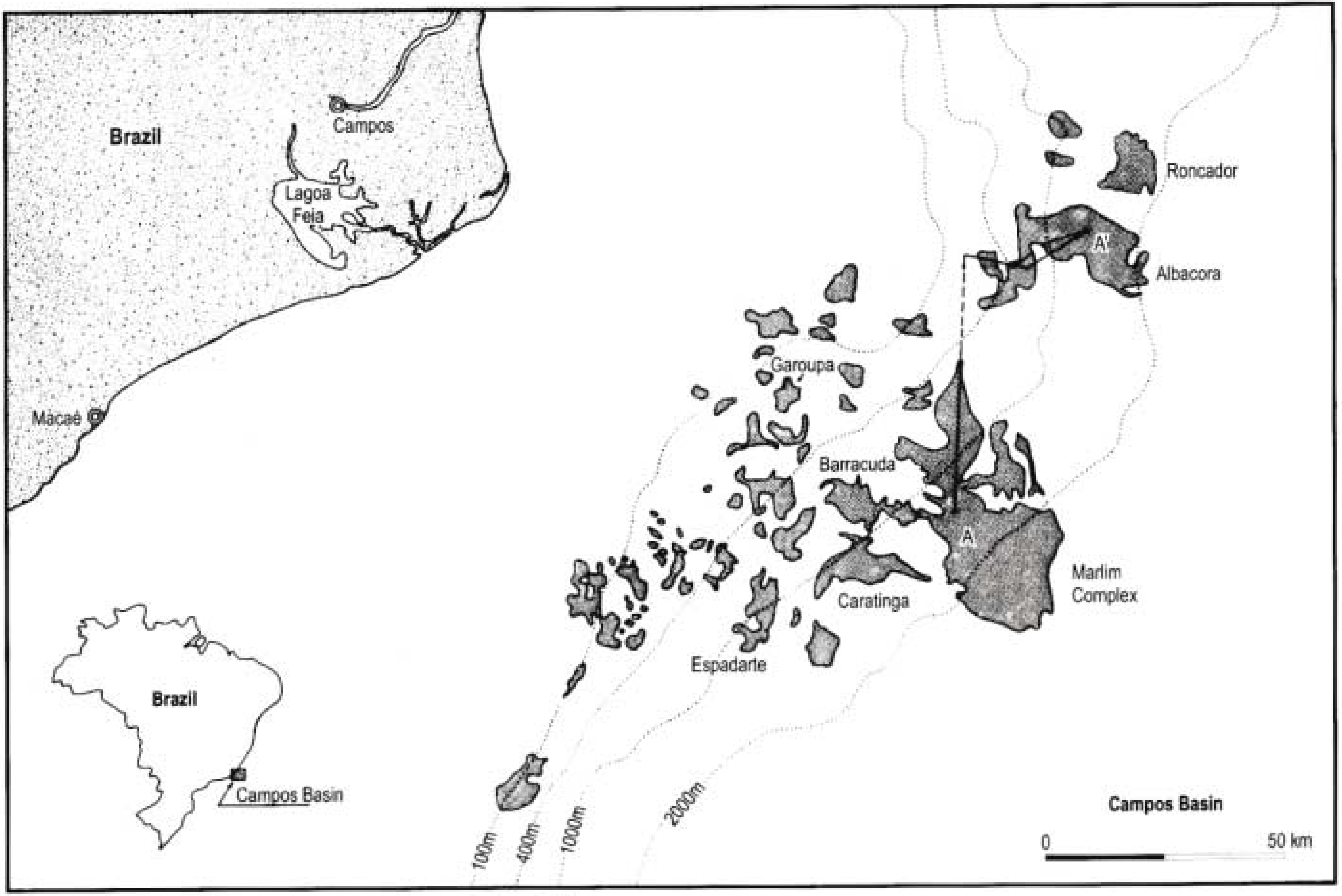


FIGURE 13 – Campos Basin map, offshore southeastern Brazil, showing the oil and gas fields.

marlstone beds (Macaé Formation) sealed the grainstone banks.

During the development of this marine carbonate environment, siliciclastic rocks and turbidite beds were also deposited, reaching the low areas between banks and carried out to the deep basin by density currents. These coarse to fine-grained sandstone beds are known as Namorado Sandstone.

The rapid subsidence of the basin during the Late Cretaceous and Tertiary was responsible for the accumulation of more than 3000 m of sediments. This sequence consists of siliciclastic and carbonate beds associated with the growth of the continental margin, and the development of a prograding complex consisting of shallow platform and deep slope to basin sediments. These sediments consist of coastal fluvial and shallow marine sandstone and shale beds, carbonate bank sediments and slope and basin floor shale and marlstone. Intercalated with the fine-grained sediments deposited on the slope and in the deeper parts of the basin, there occur zones of coarse clastic sediments resulting from periods of a relative fall in sea level and the consequent input to the deep basin of platform sandstone by density and turbidity flows. These flows were able to transport large amounts of clastic sediments to the basin floor, giving rise to thick turbidite fans, locally covering areas exceeding 200 km^2 (Carapebus Formation).

The carbonate and clastic beds of the Middle to Late Cretaceous and Tertiary section were strongly affected by intense salt tectonics, with the development of salt pillows and domes, as well as the development of listric faults with detachment surfaces in the evaporite section. Salt tectonics is responsible not only for the traps for hydrocarbon accumulation but also for the distribution of most of the turbidite units, as the bottom topography of the basin was totally affected by the movement of salt.

The Early Cretaceous lacustrine shale of Lagoa Feia Formation deposited in a shallow rift in which the environment was alkaline represents the main source rock of the basin. This Barremian sequence displays total organic carbon contents of about 4 to 6%, amorphous organic matter (type I), and yielding capacity of around 38 kg of hydrocarbon for ton of rock (Guardado *et al.*, 1997).

Biomarker data of this source rock suggest deposition in a brackish to salty water lacustrine environment, developed in shallow depressions of the rift phase. These rocks occur very extensively all over the basin, and reach a thickness varying between 100 and 300 m. The oil window was reached during the Middle Cretaceous, but only in the Miocene the maturation peak was attained. Most of the source rock sequence is still in the oil window, and only in a few deep grabens these rocks penetrated the gas window (Mello *et al.*, 1994). As a consequence the Campos Basin has a low gas/oil ratio, and the oil quality is relatively poor, varying from 14° to 32° API.

The reservoirs in this basin occur almost throughout the stratigraphic column, from the fractured basalt and coquina in the rift section; the oolitic carbonate of the shallow platform; and the turbidite beds of the deep siliciclastic basin. The main giant oil fields occur in clastic reservoirs formed from Tertiary turbidite beds.

In the rift package the oilfields are situated in internal horsts where fractured basalt and thick banks of coquina are present. These lacustrine carbonates have a porosity in the order of 15% to 20% and medium permeability values. The complex Badejo-Linguado-Trilha and Pampo fields, situated in the Badejo High, southern Campos Basin, produce oil from this interval. The original *in situ* volume is given as 660 million barrels.

The main producing Albian reservoir consists of marine oolitic carbonate. In this reservoir more than five billion barrels *in situ* original oil volume was found in a N-S oriented narrow belt of bars structured by halokinesis. The petrophysical characteristics of these carbonate banks are excellent, but may vary very rapidly in response to facies change to low-energy carbonate beds (lagoonal and open marine facies).

In the Late Albian to Turonian deep-water sequence, there occur thick units of turbiditic sandstone, associated with a phase of trangression and flooding of the basin. These turbidites known as Namorado Sandstone display a typical channeled geometry and were also strongly structured by the initial phase of salt movements. Due to the gravitational tectonics, the original low areas that captured the sand-rich density flows were completely reversed to high blocks forming natural traps to oil accumulation. The Namorado Field containing more than 120 million barrels of proven original oil, constitutes the typical oil field in this type of reservoir. It is estimated that in this petroleum sub-system more than two billion barrels of oil were accumulated *in situ*.

However the giant fields are contained in the turbiditic Tertiary section known as Carapebus Member, where more than 30 billion barrels of oil *in situ* were discovered. The turbiditic fans were formed from the Late Cretaceous to the Miocene, but the huge volume of sandstone, deposited as basin floor fans reworked by deep tidal currents are concentrated in the late Oligocene and early Miocene. This vast influx of sand in the deep basin is associated with rapid but violent sea level falls related to climatic change, creating conditions favourable for the transport of very large volumes of clean platform sands, via slope channels and, in some case, via canyons to the deep basin floor. The basin floor fans consist essentially of coalescing sandbodies up to 120 m thick and covering areas of several hundreds km^2. They have remarkable laterally and vertically continuity, with porosity values around 30% and permeability of several Darcies. These sandbodies may produce around 20 000 barrels/day per well.

In these Tertiary reservoirs the main trapping mechanism is the pinchout of the sand against the fine-grained sediments of the slope. However, halokinesis also plays an important role, since the listric normal faults generated in the salt section are responsible for the migration routes that allow the oil to reach the post salt reservoirs coming from the deep parts of the rift basin.

The migration pathway model to explain the distribution of a so large a volume of hydrocarbons in the Campos Basin was controlled by a number of factors. These controls include the presence of rift paleo-highs responsible for collecting oil from the adjacent lows; salt displacement to open window for oil ascension through the excellent seal represented by the evaporite beds; listric growth faults acting as conduits for the hydrocarbons; and finally, by the carrier beds represented by the laterally continuous carbonate and turbidite reservoirs.

Accordingly Bruhn (1998,1999) the turbidite reservoirs *contain about 71% of the oil and 60% of the gas found in* the Brazilian basins, being responsible for 89% of the proven reserves of oil and 54% of gas reserves, estimated in 14.1 billion barrels of oil and 15.4 TCF, respectively.

Albacora Field

The Albacora Field was the first discovery in the deep waters of Campos Basin, Brazil, at the end of 1984, and it lies at water depths varying from 250 m to 2000 m. The field contains six stacked reservoirs consisting of turbidite beds, the oldest deposited in the Early Cretaceous and the *youngest deposited during the Tertiary (Eocene, Oligocene* and Miocene). These reservoirs lie between 2300 and 3300 m below sea level.

The field complex covers an area of about 235 km^2 and contains an *in situ* oil volume of 4.5 billion barrels of oil and 68 billion cubic metres of gas. The deepest and oldest reservoir consists of the Namorado Sandstone (Albian-Cenomanian) lying in a horst-type trap developed by salt tectonics. The other five reservoirs are combined or stratigraphic traps, related to depositional characteristics of turbidite basin-floor fans, gently accommodated over the older structures (Fig. 14).

The total thickness of the oil-bearing sandstone may reach 110 m and the porosity varies from 17% in the older body to 30% in the Miocene sandstone. Permeability values are extremely high, in the range of 1 to 3.5 Darcies, mainly in the Oligocene sandbody, where most of the oil is trapped. The Miocene reservoir extends to very deep waters and has a very large gas cap.

The oil quality is variable in function of the reservoir depth and biodegradation processes suffered by the younger reservoirs due to their maturation low temperatures. In the Namorado Sandstone, below 3000 m, the oil presents values around 30° API, whereas in the shallower Miocene reservoirs the oil presents only 17° API (Candido and Corá, 1990).

This field is being developed since 1987, when an early production system was installed to drain and produce the shallower water reservoirs (Namorado Sandstone and Eocene beds). Only recently, a more complete development system was installed, being composed of several floating production storage and offloading (FPSO) barges and semi-submersible platforms, with capability to produce oil and gas to water depths of 1200 metres. The Miocene oil and gas reservoir, located beyond these depths will be subsequently put into production (Albacora Leste Project). The production peak of this system is estimated to reach 320 000 barrels and 5.4 million cubic metres per day of associated gas.

Marlim Field

Marlim Field is situated in the deep waters of Campos Basin, Brazil. It was discovered in 1985 by the drilling of a wildcat in a water depth of 835 m. This well, a world record for the petroleum industry at that time, had the purpose of testing a stratigraphic trap mapped and delineated on the basis of an anomaly detected on 2D seismic lines.

This seismic anomaly covering an area of about 140 km^2, was mapped in the Oligocene section and related to the presence of turbidite bodies already known in the basin *as potential producers of oil and gas in shallow water.* At about 2600 m the drill intersected massive oil-bearing sandstone some 73 m thick, displaying a very good correlation with the seismic anomaly. The production test showed a production capacity around 3800 barrels per day of oil of 19° API.

Contrary to the previously discussed Albacora Field, the Marlim Field only has one reservoir of exceptional size and lateral and vertical continuity, covering an area of about 152 km^2 (Fig. 14), and lying at water depths between 600 and 1200 m. Subsequently, several other petroleum *accumulations were discovered close to the Marlim Field,* in other Oligocene basin-floor fans, and are collectively known as Marlim Complex. This complex (Fig. 14) covers an area of about 350 km^2 and contains around 14 billion barrels of oil *in situ.*

The Marlim reservoir consists of several stacked and coalescing deep water sand-rich non-confined fan lobes, deposited rapidly during the late Oligocene, and controlled by a relative fall in sea level. The amalgamation of these fan lobes produced a very massive and homogeneous medium to fine-grained sandstone, with an average thickness of 47 m, an average porosity of 25% and permeability ranging from 1.2 to 5.4 Darcies.

The absence of fine-grained beds, usually present at the very top of each turbiditic event, is being tentatively interpreted as the result of strong and deep submarine tidal currents, known as contour currents. The presence of this type of currents would be responsible for the removal of the argillaceous material from the section and consequent cleaning of the turbidite deposits.

The main trapping mechanism acting in the Marlim Field may be described as a combined one, since to the W, N, and S there is a sand pinchout, and to the E the accumulation is terminated against a listric fault plane (Fig. 14). This fault provided the main migration pathway for oil ascension, from the source rocks in the pre-salt rift section.

Although the Marlin Field reservoir consists of a single and continuous sandstone unit the oil produced from this reservoir may vary in quality from 19° to 26° API. This variation is related to the presence of, at least, two oil migrations and filling pulses. The first one occurred probably in the late Oligocene, which is very early in the reservoir history, and may be due to the shallow burial and low temperature caused the partial alteration of the incoming oil by bacterial degradation. The second pulse occurred in the late Miocene and recharged the reservoir with lighter and more mature oil, preserved by the deeper and higher temperature conditions reached by the reservoir. The final product is an accumulation with a mixture of oils. In some places there is prevalence of one type (heavier) with respect to another (lighter), in function of some aspect of the migration patterns and pathways that is not completely understood.

The Marlim Field went on stream in 1992, through an early production system installed in the northern part of the field. Here the water depth is approximately 600 m, which permitted a better knowledge of the reservoir production capacity and pressure maintenance. This was important because only a very small amount of water had been detected in the upper parts of the reservoir. This

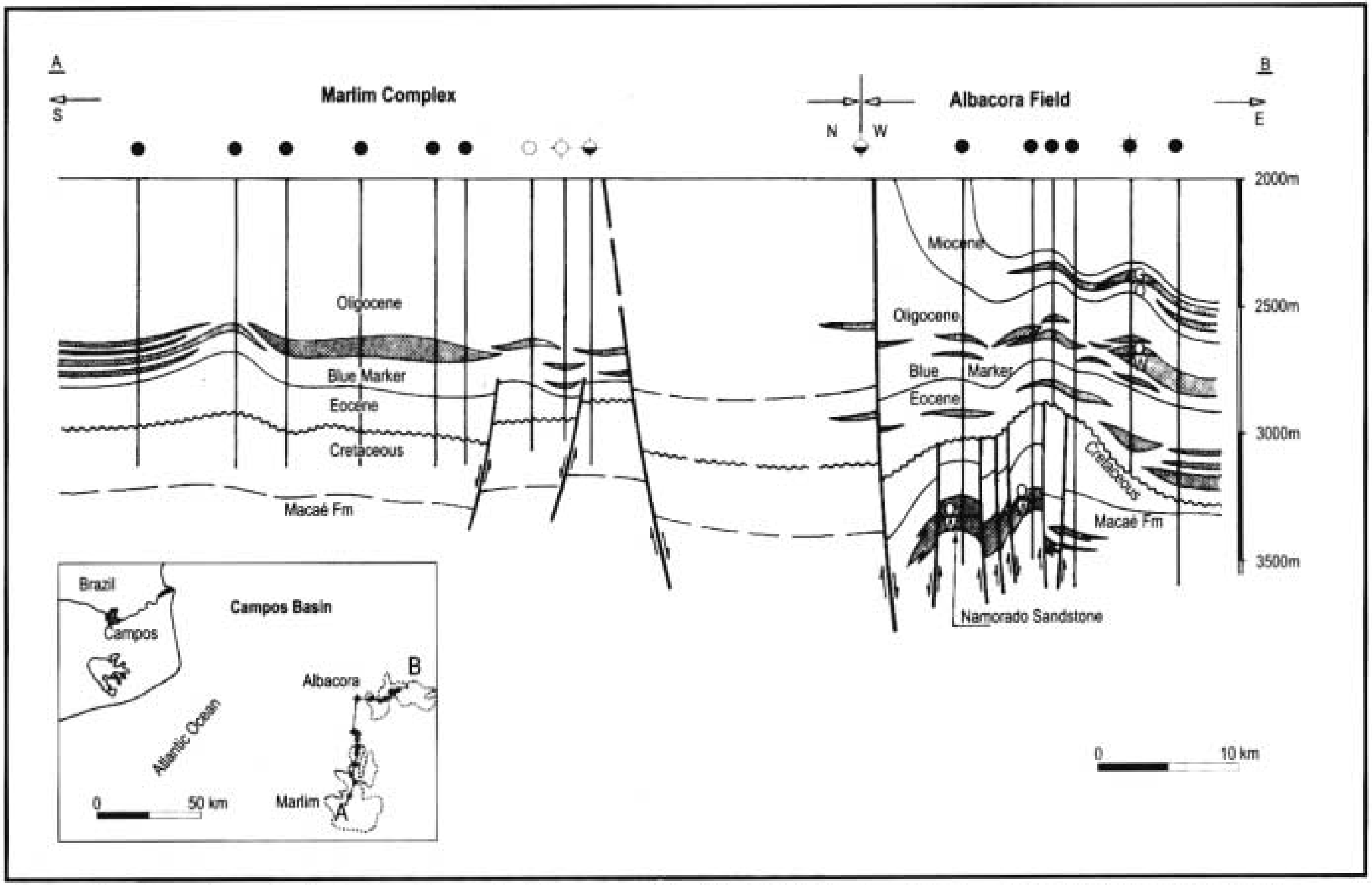


FIGURE 14 - Schematic structural cross section showing the tectonic framework and deep-water reservoir distribution of the Marlin Complex and the Albacora Field (modified after Candido and Cora, 1990).

aquifer is probably not active, and pressure maintenance measures have been required since production started.

The development project of the Marlstoneim Field will be almost complete by the end of 1999. It will consist of about 100 producing wells and 30 water injector wells drilled from six semi-submersible floating platforms (FPSO). A production peak of about 500 000 barrel of oil per day is estimated from this system. The part of the Marlstoneim Complex, lying in deeper water will be in production in the next few years.

Intracratonic Petroleum Megasystem

The Intracratonic Petroleum Megasystem is developed in the Paleozoic interior sag basins of South America. These huge, elliptical to circular shaped basins, with areas ranging between 500 000 to more than 1 000 000 km^2, share some general characteristics including the remarkable presence of large volumes of Mesozoic basaltic rocks and a relatively simple stratigraphy and structural framework (Figure 15).

On the other hand, a very complex and unusual petroleum geology should be included in this list of similarities, and it was certainly responsible for the slow response to the exploration efforts performed in these basins since the early fifties.

The South American Paleozoic syneclises were filled dominantly by siliciclastic sequences, with a notable exception represented by the Late Carboniferous-Early Permian carbonate-evaporite section present in the Solimões, Amazonas and Parnaíba basins, and to a lesser extend by the Late Permian carbonate-shale rhythmic beds of the Paraná Basin. Also remarkable was the glacial influence over the sedimentation, that was extreme during the Late Carboniferous in the Paraná Basin. The tectono-stratigraphic development of these basins started in the Late Ordovician and reached the Cretaceous (Paraná and Parnaíba), or proceeded up to the Quaternary (Solimões and Amazonas), being their stratigraphic record a succession of large-scale cratonic sequences separated by interregional unconformity surfaces.

In all these basins, the most effective source rock interval is located in the Devonian, represented by marine black shale with ages varying from Frasnian (Solimões, Amazonas and Parnaíba) to Emsian (Paraná). The reservoirs are essentially formed by sandstone units accumulated in different environments, with ages from the Devonian (Itaim and Cabeças formations in Parnaíba Basin), through the Carboniferous (Juruá and Monte Alegre formations in Solimões and Amazonas basins), to the Permian (Rio Bonito Formation in Paraná Basin). Seal is provided by thick evaporite sections in the Solimões Basin, but a Mesozoic diabase sill retained the gas in the Barra Bonita Field of the Paraná Basin.

The main trapping mechanism is structural. Mesozoic fault-propagation anticlines associated with contractional faults hold the majority of the oil and gas reserves in the Solimões Basin. Permian transpressional folds are responsible for gas accumulations in the Paraná Basin. Several minor occurrences and small oil accumulations of stratigraphic nature were discovered in the Devonian reservoirs of the Solimões and Amazonas basins and in the Permian reservoirs of the Paraná Basin (Milani and Zalán, 1998, 1999). Of these, the Solimões Basin holds most of the reserves of hydrocarbons related to the Intracratonic Petroleum Megasystem.

But the main aspect that makes the Intracratonic Petroleum Megasystem of South American basins unique is how the maturation stage of the Devonian source rocks was attained. In none of these basins, can a simple model for maturation evolution, based solely on subsidence and uplift rates and thermal input derived from crustal stretching, explain any of the observed accumulations of petroleum and associated maturation indicators.

In all these basins, the introduction of thick Mesozoic diabase had enormous thermal effects upon the maturation of the organic matter, on the level of such maturation, and also on the transformation ratio of previously accumulated hydrocarbons. In some of these basins, maturation of the organic matter was achieved only by the additional thermal input of intruding diabase into the source rocks. In others, the oil-window level of maturation was suddenly increased to the gas-window level by these intrusion. An excellent example of this type of megasystem is found in the Solimões Basin, Brazil.

Solimões Basin

The petroleum system of the Solimões Basin is formed by Late Devonian source rocks of the Jandiatuba Formation, attaining a thickness of 40 m and reaching a TOC mean value of 4% (Eiras, 1998). Vitrinite reflectance is above 1.00% all over the basin. The Late Carboniferous eolian, tidal plain and shallow marine sandstone beds of the Juruá Formation are the best reservoir in the basin. The sandy package may be as thick as 40 m, displaying porosity values around 18% and good permeability mainly in the eolian facies. Efficient seal is provided by evaporites found at the base of the Pennsylvanian Carauari Formation.

Very extensive magmatism occurred during Late Triassic to Early Jurassic and that was the time when most of the generation, expulsion, migration and accumulation of petroleum took place in the Solimões Basin. Three main, basin-scale sills were intruded roughly parallel to argillaceous bedding planes, serving as stratigraphic reference levels. Fault-propagating folds, the classic trapping style in the basin, were formed by dextral wrenching during Late Jurassic to Early Cretaceous times (Figure 16).

Pioneer exploration activities in the Solimões Basin, an area located in the middle of the Amazon jungle, began in the late 50's, but the main cycle of discoveries of hydrocarbons only started in the late 70's. Most of hydrocarbons found in this basin are composed of gas, but in several pools an oil ring is present at the base of the accumulation. This light oil and the associated liquids formed with gas (condensate) started to be produced in the 80's, after the design and construction of a complex production system in order to minimize the environmental impact of this activity in this type of tropical rainforest.

Up to now, four oil and gas provinces have been discovered in the basin: Juruá and Copacá (10 gas fields), Urucu (5 light oil/gas/condensate fields), and São Mateus

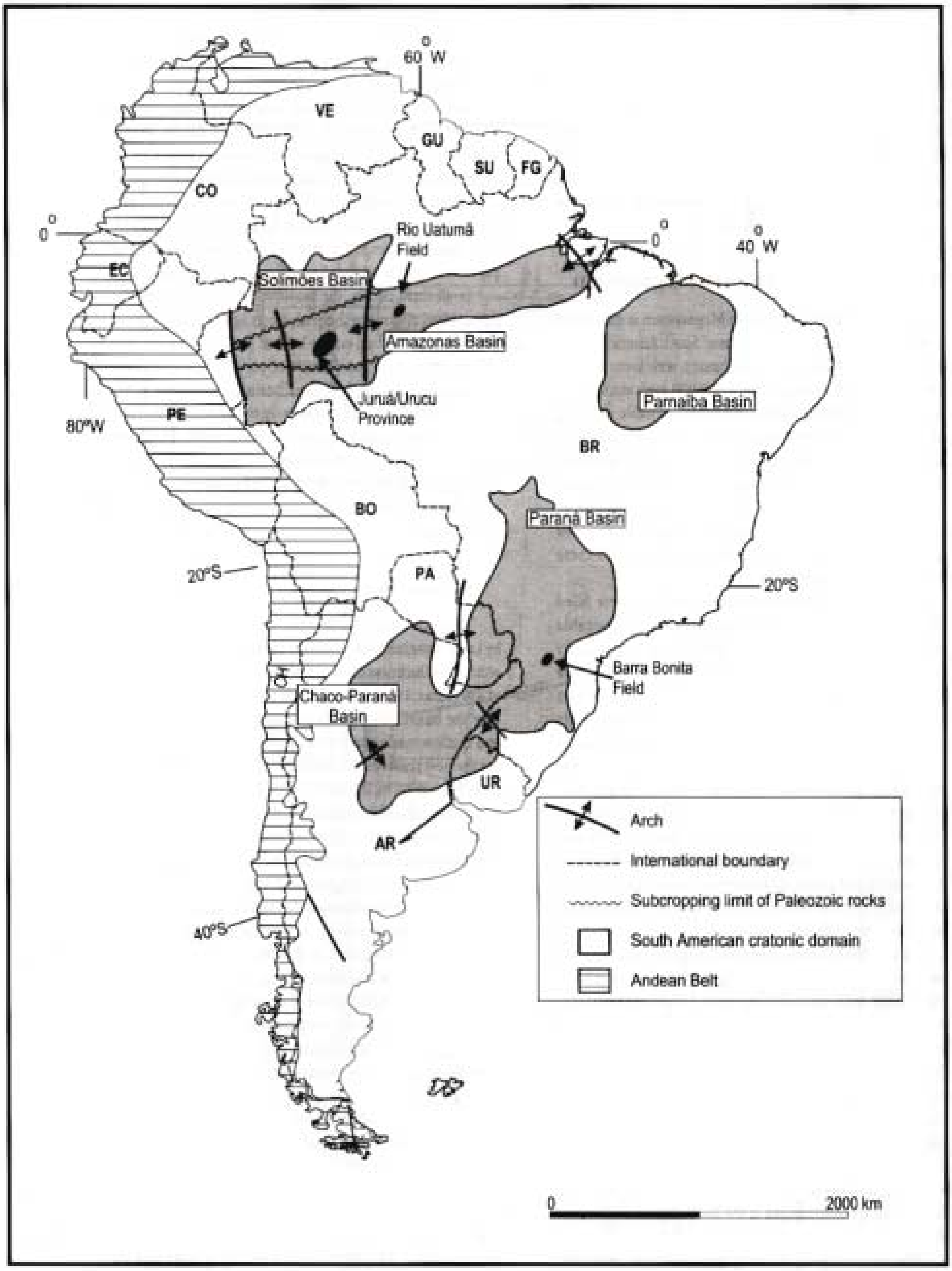
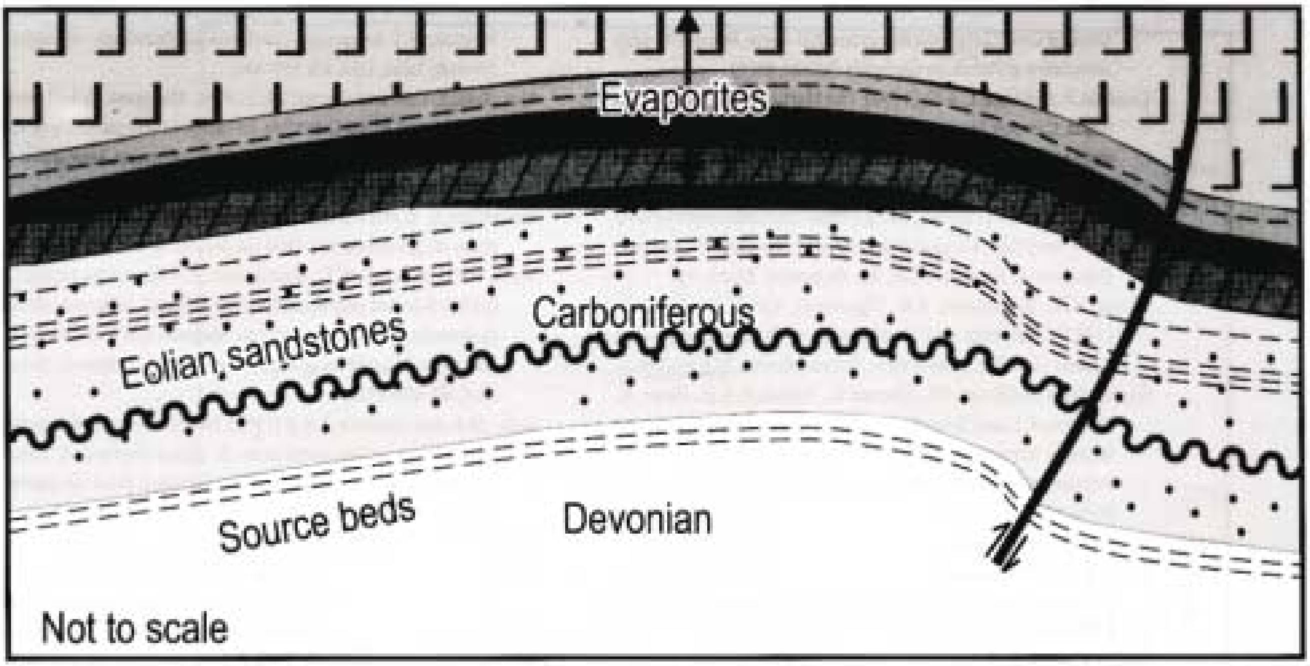


FIGURE 15 – Location map of Intracratonic Petroleum Megasystem showing the Paleozoic interior sag basins of the South American Continent, and associated oil and gas fields.

FIGURE 16 - Typical structural trap in the Solimões Basin, Brazil, where most of the reserves are located in fault-propagation folds associated with reverse faults of Mesozoic age (after Milani and Zalán, 1998).



(1 gas/condensate field and 2 gas field) provinces, holding in place reserves of 170 billion m³ of gas and 121 million m³ of oil and condensate. The present production is around 35.000 barrels of oil per day and 1.7 MMm³/day of gas, making the Solimões Basin the most important petroleum-producing Paleozoic interior sag basin of South America.

Considering the huge size of these basins and the sparse coverage of seismic data, due to adverse local conditions, it is believed that the Intracratonic Petroleum Megasystem still is one of the most promising exploration targets for the next century.

Final Remarks

After one century of active petroleum exploration, the South American basins present different stages of maturity in terms of oil and gas exploration and production. It is believed that most basins may be still classified as being in the initial stage of exploration, principally when occurring in large areas covered by dense tropical jungle, or submerged in deep waters of the continental margins of the Atlantic and Pacific oceans. A few basins such as some onshore basins in Argentina, Brazil and Venezuela may be considered as in an advanced or in a more mature stage of exploration.

Nevertheless, even in these apparently well explored basins, a remaining exploration potential is present, taking into consideration the existence of untested deep objectives for gas production, the presence of strongly deformed area affected by tectonics, and several types of pure stratigraphic traps, still badly imaged by the 2D seismic data. The advent of 3D seismic processes associated with visualization techniques, as well the development of drilling and production techniques to reach deep targets and produce oil and gas from multi-lateral and extended-reach horizontal wells brought to these basin new chances to add huge untapped reserves.

On the other hand, improvement in the extraction techniques of already discovered oil and gas pools, using 4D seismic data, and a more severe control in the production parameters, pressure maintenance, reservoir characterization and reserve evaluation will bring the recovery factor of this accumulation to levels around 60% to 70%, adding a large amount of hydrocarbons to the world reserve.

According to Kronman *et al.* (1995) the probability of finding new giant oil and gas fields (above 500 million barrel of oil equivalent of original reserve) is very high in the Campos, Maracaibo, Llanos and Maturin basins. Subgiant accumulations and medium-size fields (between 50 and 250 million barrels of oil equivalent) may occur in Neuquén, San Jorge, Austral, Tarija, Oriente (including Marañon and Putumayo) and Magdalena basins.

A global estimation for the future reserves to be found in the South American basins is around 40 to 60 billion barrels of oil equivalent. Considering that the world tendency is to sustain or improve the global reserve, the South American Continent should keep the reserve/production ratio (R/P) around fifty years in respect to oil and seventy years in respect to gas for at least one more decade. This fact and the continuous transportation and market integration of most countries will keep the energy matrix essentially based on hydrocarbons for the first half of the next century.

REFERENCES

Aymard, R., Pimentel, L., Eitz, P., Lopez, P., Chaouch, J., Navarro, J., Mijares, J. and Pereira, J.G. (1990). Geological integration and evaluation of Northern Monagas, Eastern Venezuelan Basin. In: Classical Petroleum Provinces, ed. Brooks, J. *Geological Society Special Publication*, 70, 37-53.

Bruhn, C.H. (1998). Deep-water reservoirs from the Eastern Brazilian rift and passive margin basins. In: *Petroleum geology of rift and passive margin turbidite systems; Brazilian and worldwide examples.* AAPG/ABPG International Conference and Exhibition Short Course Notes 6, Rio de Janeiro, Brazil.

Bruhn, C.H. (1999). Reservoir architecture of deep lacustrine sandstones from the Early Cretaceous Reconcavo Rift-basin, Brazil. *American Association of Petroleum Geologists Bulletin*, **83**(9).

Candido, A. and Cora, C.A.G. (1990). The Marlin and Albacora giant fields, Campos Basin, Brazil. In: Giant oil and gas fields of the decade 1978-1988, ed. Halbouty, M.T. *American Association of Petroleum Geologists, Memoir*, Tulsa, **54**, 123-135.

Carneiro, E.P. and Cavalcanti. A.R.S. (1994) The Cretaceous Oriente Basin revisited: a regional overview. In: *Anais do V Congresso Brasileiro de Petróleo e Gás*, Rio de Janeiro, Brazil, 9 p.

Chang, H.K., Kowsmann, R.O., Figueiredo A.M.F., Bender, A.A. (1992). Tectonics and stratigraphy of the East Brazil Rift System (EBRIS): an overview. *Tectonophysics*, **213**, 97-138.

Cooper, M. A., Addison, F.T., Alvarez, R., Hayward, A.B., Howe, S., Pulham, A.J. and Taborda, A. (1995). Basin development and tectonic history of the Llanos Basin, Colombia. In: (eds.) Petroleum basins of South America, eds. Tankard, A.J., Suárez Soruco, R. and Welsink, H.J.. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **62**, 659-665.

Daly, M.C. (1989). Correlations between Nazca/Farallon Plate kinematics and forearc basin evolution in Ecuador. *Tectonics*, **8**, 769-790.

Dengo, C. A. and Covey, M.C. (1993). Structure of the Eastern Cordillera of Colombia: implications for trap styles and regional tectonics. *American Association of Petroleum Geologists Bulletin*, **77**, 1315-1337.

Dow, W.G. (1974). Application of oil-correlation and source-rock data to exploration in Williston Basin. *American Association of Petroleum Geologists Bulletin*, **68**, 1752-1763.

Eiras, J.F. (1998). Geology and petroleum system of the Solimões Basin, Brazil. *Rio'98 AAPG International Conference and Exhibition, American Association of Petroleum Geologists/ Associação Brasileira de Geólogos de Petróleo, Extended abstracts volume*, p. 446.

Figueiredo, A.M.F., Braga, J.A.E., Zabalaga, J.C., Oliveira, J.J., Aguiar, G.A., Silva B., Mato, L.F., Magnavita, L.P., and Bruhn, C.H. (1994). Recôncavo Basin, Brazil: a prolific intracontinental rift basin. In: Interior rift basins, ed. Landon, S.M., *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **59**, 157-204.

Grieco, L. F. (1991), Distribución de fluidos en la estructura de Aguarague. *Boletín de Informaciones Petroleras*, **26**, 61-66.

Guardado, L.R., Spadini, A.R., Mello, M.R. and Brandão J.S.L. (1997). Petroleum systems of the Campos Basin, Brazil. In: *AAPG/ABPG Hedberg Research Symposium, Petroleum systems of South Atlantic Margin. Extended abstract.* Rio de Janeiro, Brazil.

Jaillard, E., Soler, P., Carlier, G. and Mourier, T. (1990). Geodynamic evolution of the northern and central Andes during the early and middle Mesozoic times. *Journal of Geological Society of London*, **147**, 1009-1022.

Kronman, G. E., Rushworth, S. W., Jagiello, K. and Aleman, A. (1995), Oil and gas discoveries and basin resources prediction in Latin America. In: Petroleum basins of South America, eds. Tankard, A.J., Suárez Soruco, R. and Welsink, H.J. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **62**, 53-61.

Legarreta, L., Laffite, G. A. and Minniti, S. A. (1999). Cuenca Neuquina: múltiples posibilidades em las Series Jurásico-Cretácicas del depocentro Periandino. In: *Actas del IV Congreso de Exploracion y Desarollo de Hidrocarburos*, Mar del Plata, Argentina, **1**, 145-175.

Lugo, J. and Mann, P. (1995). Jurassic-Eocene tectonic evolution of Maracaibo Basin, Venezuela. In: Petroleum basins of South America, eds Tankard, A.J., Suárez Soruco, R. and Welsink, H.J. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **62**, 699-726.

Mathalone, J.M.P. and Montoya M.R. (1995). Petroleum Geology of the Sub-Andean Basins of Peru. In: Petroleum basins of South America, eds. Tankard, A.J., Suárez Soruco, R. and Welsink, H.J. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **62**, 423-444.

McCollough, C.N. and Carver, J.A. (1990). The giant Caño Limon Field, Llanos Basin, Colombia. In: Giant oil and gas fields of the decade 1978-1988, ed. Halbouty, M.T. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **54**, 175-196.

McGettigan, C. K. and Hunt, D. G. (1996). Colombia continues to yield major oil, gas discoveries. *Oil & Gas Journal Special*, July, **15**, 40-45.

Mello, M.R., Mohriak, W.U., Koutsoukos, E.A.M. and Bacoccoli, G. (1994). Selected petroleum systems in Brazil. InThe petroleum systems from source to trap, eds. Magoon, L.B. and Dow, W.D. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **60**, 499-512.

Mello, M.R. and Trindade, L.A.F. (1996). Nuevas metas exploratorias em cuencas latinoamericanas de aguas profundas: cómo proceder con el concepto de sistema petrolero. *Oil & Gas Jounal, Revista Latinamericana*, **2**(1), 25-32.

Milani, E.J. and Zalán, P.V. (1998) *Brazilian Geology Part 1: the Geology of Paleozoic Cratonic Basins and Mesozoic Interior Rifts of Brazil.* Rio'98 AAPG International Conference and Exhibition, American Association of Petroleum Geologists/ Associação Brasileira de Geólogos de Petróleo, Short Course Notes, Rio de Janeiro, Brasil.

Milani, E.J. and Zalán, P.V. (1999). An outline of the geology and petroleum systems of the Paleozoic interior basins of South America. *Episodes*, **22**(3), 199-205.

Mpodozis, C. and Ramos, V. (1989) The Andes of Chile and Argentina. In: Geology of the Andes and its relation to hydrocarbon and mineral resources: Circum-Pacific Council for Energy and Mineral Resources, eds. Ericksen, G.E., Cañas Pinochet, M.T. and Reinemund, A. *Earth Science Series*, **11**, 59-90.

Pittion, J.L. and Arbe, H. (1997). Petroleum systems in the Austral Basin. In: *AAPG/ABPG Hedberg Research Symposium, Petroleum systems of South Atlantic Margin, Extended abstract.* Rio de Janeiro, Brazil.

Prieto, R. and Valdes, G. (1990). El Furrial oil field a new giant in an old basin. In: Giant oil and gas fields of the decade 1978-1988, ed. Halbouty, M.T. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **54**, 155-163.

Ramírez, E. and Marcano, F. (1990) Ceuta-Tomoporo Field, Venezuela. In: Giant oil and gas fields of the decade 1978-1988, ed. Halbouty, M.T. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **54**, 163-174.

Robbiano, J.A., Arbe, H.A. and Gangui, A. (1996). Cuenca Austral Marina. In: Ramos, V.A. and Turic M.A. (eds.). *XIII Congreso geológico Argentino y III Congreso de exploracion de hidrocarburos. Geología y recursos naturales de la Plataforma Continental Argentina*, pp. 323-341. Buenos Aires, Argentina.

Schamel, S. (1991). Middle and Upper Magdalena basins, Colombia. In: Active margins basins, ed. Biddle, K.T. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **82**, 283-301.

Szatmari, P., Milani, E.J., Lana, M.C., Conceição, J.C.L. and Lobo, R.P. (1985). How South Atlantic rifting affects Brazilian oil reserves distribution: *Oil and Gas Journal*, **83**, 107-113.

White, H.J., Skopec, R.A., Ramirez, F.A., Rodas J.A. and Bonilla G. (1995). Reservoir characterization of the Hollin and Napo formations, western Orient Basin, Ecuador. In: *Petroleum basins of South America*, eds. Tankard, A.J., Suárez Soruco, R. and Welsink, H.J. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **62**, 573-596.

Vergani, G.D., Tankard, A.J., Belotti, H.J. and Welsink, H.J (1995). Tectonic evolution and paleogeography of the Neuquen Basin, Argentina. In: Petroleum basins of South America, eds. Tankard, A.J., Suárez Soruco, R. and Welsink, H.J. *American Association of Petroleum Geologists, Memoir*, Tulsa, USA, **62**, 383-402.