AAPG Annual Convention
Salt Lake City, Utah
May 11-14, 2003

Comparative Response of Seismic Signatures in Deep-Water Reservoirs Offshore Brazil and West Africa

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Abstract

The main oil producing basins offshore Brazil are situated in the east coast and its deepwater realm has been site of the most significant oil and gas discoveries. Turbidite reservoir oil fields were discovered in the Campos Basin province, these include giant deepwater accumulations such as Marlim, Albacora, Barracuda, Roncador and Jubarte. This study performs a statistical characterization of the seismic responses in deep-water reservoirs off Brazil and compare them with similar occurrences offshore West Africa. The deepwater turbidite reservoirs off Brazil occur in basin floor fan, prograding wedge and slope fan systems tracts. Pre-stack time and depth migrated 2D and 3D seismic data, and attribute analyses, ties the reservoir responses to high amplitude, high continuity, and hummocky amplitudes, lower continuity reflectors. Seismic interpretation of modern data has mapped, through high-resolution imaging, the stratigraphy of these hydrocarbon producing turbidite reservoirs.

Most of the deepwater reservoirs are constrained, structurally, by massive but autochthonous salt. Hydrocarbon migration into the Brazil fields is from syn-rift source rocks via large faults, these breach the salt where it is welded.

Next exploration frontier are turbidites in ultra deepwater. Play types include both structural and stratigraphic components. Salt-related, large four-way closures, including faulted and non-faulted turtle structures and drapes over massive salt have been identified along with sub-unconformity traps. These are associated with amplitude anomalies, which are widespread throughout the deepwater basins both off Brazil and West Africa.

Introduction

Offshore Brazil's main oil-producing province is in the deepwater realm of Campos Basin and accounts for 80% of the Brazilian daily output. Its main oil fields, Roncador, Albacora, Marlim, Barracuda, Espadarte and Caratinga make up for more than 90% of the Brazilian proven reserves (table 1). Reservoirs in these deepwater fields are turbidites that range in age from Upper Cretaceous to Miocene (Guardado et al., 1989). All of the producing oil and gas fields of Campos Basin are situated within Petrobras's ring fence and were all discovered between 1985 and 1997, these are the Marlim, Marlim South, Marlim East, Albacora, Albacora East, Barracuda, Congro, Caratinga, Frade, Marimbá, Espadarte and Roncador fields. Among these, Albacora, Albacora East, Frade and Roncador fields are situated in the North Campos Basin whereas the Marlim Field, Barracuda, Caratinga and Espadarte are situated in the Central and Southern parts of the basin. The main oil reservoirs of the deep-water oilfields are in reservoirs consisting of shelf-derived turbidite sands encountered in the upper and lower continental slope ranging from the Miocene to Upper Cretaceous Maastrichian-Santonian, and in distal marine turbidite channel sands of the lower slope, these are mainly found in Miocene sequences.

Assembled in 1996 by the Brazilian government, the Agência Nacional do Petróleo (ANP) opened the Brazilian upstream market to competition. Since then an intense renewal of exploration has taken place mostly in the form of farm-out partnerships and longer-term exploratory programs resulting from bid rounds. Capital investments of this new exploratory phase have been generally concentrated in eastern Brazil, in the Campos, Santos and Espirito Santo basins that are generally deemed by E & P companies to have the best risk/reward oil plays. ANP has also regulated, since 1998, geophysical data acquisition with direct impact in the acquisition of numerous, high quality, modern, multiclient seismic surveys. In Brazil, modern 2D and 3D seismic data acquisition and processing, both onshore and offshore, have dramatically improved data quality and reduced turnaround times (Fainstein, 1999). Long streamers, up to 8 km in length, large 3D acquisition footprints, and pre-stack time and depth migrations, with higher-order normal moveout, are now increasingly employed. This resulted in newly built seismic libraries with much improved imaging resolution of deepwater reservoirs, salt structuring, and of the pre-salt syn-rift source rock section.

Significant turbidite discoveries have been effected recently offshore East Brazil in the Santos, Campos, Espirito Santo, Bahia and Sergipe-Alagoas basins. Two of the most significant deep-water discoveries were in salt related turtle structures of the Santos Basin, one in Upper Cretaceous turbidites of Block BS-500 and another on Eocene turbidite channels of Block BS-4. This latest discovery, effected recently in 2002, is on Tertiary turbidite reservoirs. Another discovery still in Santos Basin South was effected on the southerly-situated Block BS-3 where the oil-bearing reservoirs are Albian carbonate build-ups. In the Campos Basin the important new discoveries were all in deep and ultra deep-water. Four significant turbidite reservoir oil finds were effected in the Campos Basin two of them on Block BC-60, plus significant recent discoveries on Blocks BC-2, BC-10, BC-200 (Albian carbonate reservoir) and BC-600. In the Espírito Santo Basin a new fairway gas play is being developed. It consists of turbidite reservoir terminating against the salt wall, essentially a stratigraphic play. Two discoveries were oil and gas in Jurassic sands offshore Bahia on Block BCAM-40 and deep-water turbidites on Bseal –100 bock off Sergipe-Alagoas.

Database

This paper utilizes the largest single 2D survey shot offshore Brazil, namely Brasil '99/2000, a 225,000-line km program, from which 140,000 line-km covered the Santos, Campos and Espirito Santo basins. The 2D surveys together form a grid of seismic data that varies from 8 by 8 km to 4 by 8 km. The paper also utilizes modern 3D seismic programs shot over selected portions of these basins. A regional structural interpretation carried out on this data set was integrated with gravity, magnetic and geochemistry data that was acquired concurrently (Figure 1). These 2D surveys were acquired utilizing 8,000-meter streamers. This long cable spread has helped substantially improve the imaging of the deeper section, in particular the lacustrine syn-rift hydrocarbon source section. Imaging of this early Cretaceous stratigraphy is fundamental for a regional understanding of the oil and gas plays. Pre-stack time migration has been applied to these surveys. This has also greatly improved imaging of salt-sediment interfaces and the delineation of turbidite fans, the major reservoirs in the deepwater petroleum system. Publicly available data from wells has also been tied into the seismic over the entire east coast off Brazil

Regional Structuring/Stratigraphy

The principal oil basin off Brazil is Campos Basin; it lays along the eastern coast offshore Rio de Janeiro State. All major deepwater Brazil fields discovered to date are within the Campos Basin. Bordering Campos's basin, south of the Cabo Frio High, is the Santos Basin where producing deep-water reservoirs have been encountered more recently. These are situated in the northern portion of the basin, near the Cabo Frio Basement High. Santos Basin extends from offshore Florianopolis, a basement high that delimits its southern frontier to the Cabo Frio region offshore Rio de Janeiro its northern border that separates the Santos Basin from the Campos Basin. The prospective area of Santos Basin is approximately 210,000 km^2, making it one of the largest basins in the world. By contrast, Campos Basin embraces a much smaller area of approximately 100,000 km^2, and is reaching a mature stage of exploration. To the north of the Campos Basin, beyond the Vitória High, is the Espírito Santo Basin that is still lightly explored in deep-water.

The structures of the Brazilian continental margin are typical of passive rifted margins. Horsts and grabens characterize basement relief. Oil and gas plays are mostly confined to stratigraphic features related to the higher horst blocks. Salt diapirism exists abundantly along the eastern margin and salt structuring is characteristic of many offshore Brazil basins. Structural trends of these basins often parallel the coastline, particularly in the Campos Basin where the system of down-to-basin faults strikes generally parallel to the coastline. East-west displacement trends are associated with South Atlantic fracture zones and reactivated SE-NW pre-Cambrian trends

There are four distinct depositional environments within the Brazil continental margin (Figure 2):

• Continental red shales and conglomerates of the pre-rift sequence.
• Fine-grained lacustrine sandstones, some of which may form potential reservoirs, and hydrocarbon-rich source rock shales of the syn-rift sequence.
• Halite, anhydrite and clastic deposits of the Albian-Aptian evaporitic sequence deposited during restricted ocean circulation south of the equatorial South Atlantic.

• Marine sequence including shallow platform carbonates and deeper open marine deposits that contain the large deepwater discoveries.

In the northern and central Santos Basin and through South Campos Basin lies the Cabo Frio fault zone, consisting of a massive structural collapse of strata near the shelf-break. This phenomenon occurred as result of rapid progradation of the mid-Albian to Late Cretaceous deep-water fans onto a thick mobile salt sheet. The progradation of the fans caused the salt mass to be displaced eastwards towards deep water creating a gap in the Albian carbonate section, an absence of Albian age sediments in this region associated with over 50 km of horizontal displacement. Salt that deposited in the rift basin now occupied by the Cabo Frio Fault Zone has been displaced eastwards. The extension seen in the compressional features in the salt ridges balance the fault zones.

The massive salt walls extend through all deepwater regions of Santos, Campos and Espírito Santo basins. In the Santos Basin, it, locally, attains thickness in excess of 5 km, this are features characteristic of the São Paulo Plateau. The salt wall may preclude hydrocarbon migration from the syn-rift source rocks into the Upper Cretaceous and Tertiary reservoirs. The salt diapirism motion is also intense near to the continental/oceanic crustal boundary. The distribution of salt impacts the architecture distribution of petroleum prospects therefore the mapping of top salt (Figure 3) is also a map of prospects overlying and terminating against the salt wall and a map of the distribution of the interspersed mini-basins in ultra deep-water.

Exploration History – Turbidite Discoveries

In Brazil, oil was first discovered in 1938, near Lobato, in the Recôncavo Basin, onshore Bahia state, the first oil producing basin of Brazil. Petrobras' first strike of oil offshore was effected in 1968 at the Sergipe-Alagoas Basin in the northeast shelf. In the Campos Basin, offshore Rio de Janeiro, the first well was drilled in 1971. The first oil strike was made in 1974 with the drilling of the eighth well the 1-RJS-9 well (Ponte et al., 1977). Oil production started in 1977 and so far more than 60 oil and gas fields have been discovered in the Campos Basin, seven of which are giant oil fields, all in deep-water turbidite reservoirs. The largest oil field, the Marlim Field (Figure 4), was discovered in 1985.

The first large discovery in Campos Basin was the Namorado Field (Baccocoli et al, 1980), however, all of the giant discoveries were made essentially between 1985 and 1997, these were the Marlim, Marlim South, Marlim East, Albacora, Albacora East, Barracuda, Congro, Caratinga, Frade, Marimba, Espadarte and Roncador fields. As of January 2003, Campos Basin produces 1,500,000 barrels of oil per day (see Table 1) or roughly 80% of the daily Brazilian output.

Exploration of the, southerly adjoining, Santos Basin began in 1970 and occurred largely on the shelf (Mohriak et al., 1995). Oil reservoirs have been since been encountered in the Albian carbonates in the south, and in Upper Cretaceous sands in the central and northern Santos Basin. The first commercial hydrocarbon accumulation was the Merluza Gas Field, discovered in 1979. This field's first well drilled through Tertiary and Cretaceous clastics into the Albian Guarujá limestone, deeper than 5,000 meters. A thin gas zone was recognized in an Upper Cretaceous shallow marine sandstone and also in a Turonian turbidite sand. In 1984 a well was drilled three kilometers north of the first well that was a gas condensate discovery in an Itajai Formation, a turbidite with 26 meters of pay with 20% porosity. Five other Albian reservoir petroleum accumulations were subsequently discovered by Petrobras; Tubarão, Coral, Estrêla do Mar, Caravela, and Caravela Sul. These Albian oil reservoirs tend to occur near the Florianópolis Platform whereas the Upper Cretaceous sand reservoirs are more typical of the central and northern Santos Basin.

The deepwater hydrocarbon potential of the Santos Basin was finally confirmed with the oil strike of September 1999 from the 1-RJS-539 well in the northern Santos Basin, reported by Petrobras as a significant discovery in deepwater Upper Cretaceous turbidite sands. This well was spudded in a water depth of 5,300 feet and is being delineated. In 2002 another significant discovery was effected nearby, in deepwater of Block BS-4 when Eocene turbidite sands were penetrated on top of a turtle structure (Figure 5).

In the Espírito Santo Basin, situated to the north of Campos Basin, exploration started early during the 1950's decade with mapping performed by CNP and Petrobras. The first discovery was made at Fazenda Cedro, in which oil entrapment was related to a paleohigh immediately below a pre-Urucutuca Fm. unconformity. Subsequently, Petrobras discovered more than fifty small accumulations, from which only five are offshore. The most important offshore oil pool is the Cação Oil Field discovered in 1977, in a similar structure to Fazenda Cedro. The reservoir of Cação Field is an early Albian siliciclastic rock within a paleohigh associated with the Santonian erosional event. There are two recently discovered gas fields in the offshore part of the Espirito Santo basin, Peroá and Cangoá, these are associated with turbidite sandstones that pinch-out against the flank of piercement salt domes. These gas fields are under development.

Still, the most important discoveries since 1999 are by and large within deep-water Campos Basin in Blocks BC-2, BC-10, BC-60, BC-200 and BC-600.

Petroleum Systems

Several distinct petroleum systems occur in the Brazilian marginal basins and are associated with: a) lacustrine syn-rift source rocks; b) restricted marine and transitional environments and c) open marine transgressive sediments. The best source rocks are within the syn-rift sequence. Reservoirs and seals occur within the syn-rift, transitional and marine sediments.

Oils found in the Campos Basin were all derived from the same organic shale source rocks, these are the rift-phase Buracica, Jiquiá and Alagoas shales (see figure 2). Sediments of the Lagoa Feia Formation reached the oil generation window about Eocene time and are presently along this zone. The source rocks are separated from the main reservoirs by a salt layer. The oil migration from source to reservoirs, therefore, required pathways either through thin salt windows or through large displacement faults that connected syn-rift and open marine sequences. Hence, migration pathways were developed as a consequence of thinning and evacuation of the salt layer during the salt movement. Rift—phase faults permitted movement of oil from source beds to reservoirs at the base of the salt, and where salt is present, oil reached the younger reservoirs along faults related to salt movement.

The new province of giant fields appears situated in the deep to ultra deep-water areas where there is greater salt mobilization. The very high prospectivity of the Campos Basin is explained by a series of factors such as oil generation, adequate timing of hydrocarbon migration and wide distribution of stacked distal turbidite reservoirs ranging from Early Cretaceous to Miocene. These are interspersed within a series of regional seals, mostly shales with high sealing capacity. Future prospectivity will tend to be focused in ultra deep water, in turbidite bright-spots in mini-basins before or within the salt wall (Figure 6).

Large turbidite fans have been identified seismically in the ultra deepwater Santos Basin. In addition, the more landward wells have penetrated the pre-Aptian section that contain acid and basic igneous rocks, with indications of coquinas, a proven reservoir in the Campos Basin, in the coarse clastic sequences dated as late as Barremian. These are expressed seismically as sub-horizontal reflectors below the base salt unconformity. Above the Aptian evaporite layers there is a dolomitized section of Albian carbonates. The transition to an open marine environment is marked by a widespread limestone platform in the early Albian. These grade from a shallow marine to a deepwater depositional environment by Cenomanian time.

The Sao Paulo Plateau is surrounded by numerous deep rift valleys that are probably source rock rich. In this region, deepwater turbidite sands pinch-out against the flanks of the salt. Hydrocarbons may have migrated updip from basin lows to the structural highs from west to east. The São Paulo Plateau was probably exposed during Early Albian to Late Cretaceous and large carbonate banks may have developed that are now located within the present day ultra deepwater realm. In the southern Santos Basin there is a southerly reduction in the amount of salt, which eventually disappears approaching the Florianópolis Platform. Sizable carbonate build-ups occur in the Albian that are reservoirs for all of the fields discovered thus far in the southern Santos Basin.

Reservoir Seismic Character

Stacked turbidite sands with high porosity and permeability are a common characteristic of the reservoirs in all of the offshore Brazil example fields. Oil-bearing sands are encountered in the Upper Cretaceous, Eocene, Oligocene and Miocene sections. In many instances the oil and gas lowstand reservoirs produce high amplitude hummocky reflectors. In addition, bright spots, flat spots and AVO effects have also been identified seismically. Examples are described below.

Marlim Field

This giant field was discovered in 1985 in 300 to 1800m water depths, covering an area approximately 50 by 15km. The reservoir sandstones lie in an Oligocene-aged lowstand turbidite complex (Figure 7). Sandy shelf deposits flowed down slope through submarine canyons to more stable locations, creating well-sorted, fine-grained basin floor fans (Candido and Costa, 1990). Where the turbidite flows encountered the base of the slope, sands tended to fill in paleo-structural lows and were reworked by bottom currents. These paleo-lows correspond with early salt evacuation.

Seismic data response over the field reveal hummocky, high amplitude events, characteristics common to unconfined turbidite complexes. Pinchouts are observed in places against paleo highs. The high amplitude seismic reflection is most likely due to higher porosity zones (20% to 30%) in the sandstone reservoir, and therefore relatively low velocity compared to the overlying shale. Faulting, caused primarily by salt evacuation, is observed on the seismic data, adding a structural component to largely stratigraphic trapping mechanisms. Furthermore, salt weld faulting is crucial for hydrocarbon migration from the source rocks beneath the Aptian salt to the overlying Oligocene reservoir.

Albacora Leste

This field is located in water depths of 800 to 1800m extending over an area of approximately 10 by 20km. Oligocene/Miocene reservoirs are part of largely unconfined lowstand turbidite flows and comprise fin grained, well-sorted sands with excellent porosity and permeability. Seismic data over the field shows a 200-300ms thick Oligocene lowstand systems tract with a high amplitude turbidite deposit at its top. The higher porosity zones of the sandstone reservoir most likely produce lower seismic velocities in this turbidite (Rosa, 1987). A highstand systems tract comprising continuous, low amplitude, seismic events, overlies the lowstand unit. Reflection amplitudes dim over the structural high.
The Albacora Leste field is a combined structural and stratigraphic trap (Figure 8). Listric faults, observed on seismic data, play an important role in controlling turbidite deposition, as well as the trapping of hydrocarbons that migrated from the early Cretaceous source beneath the salt layer.

Roncador

This giant field occurs in water depths of 1700 to 1900m, covering an area of 10 by 14km. Recoverable reserves are still under assessment, however, they are deemed at more than 2.5 Bbbls making this oil field the second largest of Brazil after Marlim. Santonian-Maastrichtian turbidite reservoir sands of Roncador have been subjected to more compaction than the younger Oligocene turbidite sands of Albacora Leste and Marlim, and therefore are likely to have overall lower porosity. Still, Roncador porosities, locally, reach 30%. Seismic amplitudes tend to vary from low in the lower porosity zones to high in higher porosity zones (Figures 9 and 10). The seismic character of the turbidite sands is slightly hummocky and mounded. Low amplitude, continuous seismic events occur both above and below the turbidite zone. Significant faulting towards the edge of the reservoir is observed on seismic data, providing hydrocarbon migration pathways from the early Cretaceous syn-rift source below. The regional seismic expression of the Roncador field is shown on Figures 9 and 10, close-up on Figure 6.

West Africa

Offshore West Africa the main discoveries in deep and ultra deep water have been made in the last five years. These include Girassol, Dalia oil fields in the Lower Congo Basin offshore Angola. The golden blocks 15 and 17 offshore Angola continue to yield new turbidite reservoir discoveries in deep-water. To these add the giant Kuito Field of Block 14.
The seismic signature response of reservoirs is quite similar when compared with the Brazilian counterparts (Figure 12). The seismic responses may be particularly well compared with the newly acquired seismic datasets. In addition to the seismic signature comparisons of oil fields the new data reveals numerous, still untested, play types that include

both structural and stratigraphic components. In West Africa deep-water there are a slew of large salt related 4-way closures, inclusive turtle structures and drapes over salt identified along sub-unconformity traps (Figures 12 and 13). All these identified play types are associated with amplitude anomalies.

Hydrocarbon Potential - Creaming Curves

The modern seismic data offshore Brazil has brought to light a number of potential deepwater untested plays in Campos Basin and in the adjoining Santos and Espirito Santo basins. These include; faulted potential 4-way closures; truncations against large salt diapirs, sometimes overhanging; truncations beneath the top Cretaceous unconformity; closures, both faulted and unfaulted, in drapes over salt; large salt withdrawal turtle structures; and stratigraphic pinchouts. All of these plays also have examples with associated amplitude anomalies. The creaming curve of turbidite reservoirs in Campos Basin is conducive to a still higher exploration potential (Figure 14).

For these plays to be viable there are a number of key factors, which must be present. Firstly there must be a nearby well-developed source section. This is typically identified seismically by low frequency, high continuity reflectors beneath the salt. Another important factor is the ability of the hydrocarbons to migrate through the salt interval and into the reservoir section above. This is best achieved with the presence of thin or welded salt, and can be augmented by large faults, which can occasionally breach the salt (Fainstein, 1999). Sealing capacity is regional in deepwater and provided by finer clastics.

The prospects around the salt wall, in the intervening mini-basins, consist of terminations of turbidite beds of Upper Cretaceous age against the salt wall. This play, of course, is still untested, due to the economic cost, and is compounded by uncertainties about salt versus sediment stratification in the mini-basins. However, the new seismic dataset has significantly improved imaging of the well-developed syn-rift sections that suggest new plays in prospective reservoirs in the early Cretaceous Guaratiba, such as the coquinas of the Barremian/Early Aptian, and also in lacustrine sandstones

Conclusions

Seismic signatures of the salt basins distal turbidite reservoirs offer an exploratory tool that will be increasingly utilized in the forthcoming exploration of the outer slope and rise segments of the continental margins offshore Brazil and West Africa adding to the slew of producing turbidite reservoirs in the Campos Basin. This has been recently underscored by discoveries in the Brazilian side on blocks BC-2, BC-60 and BC-200 and BC-600 in the Campos Basin and by the discoveries in deep-water of North Santos Basin. Deep-water geophysical development and ultra deepwater exploration is set to increase dramatically during the next five years. New plays have also been identified in the massive salt bounded mini-basins of Upper Cretaceous age and also within the syn-rift section.

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