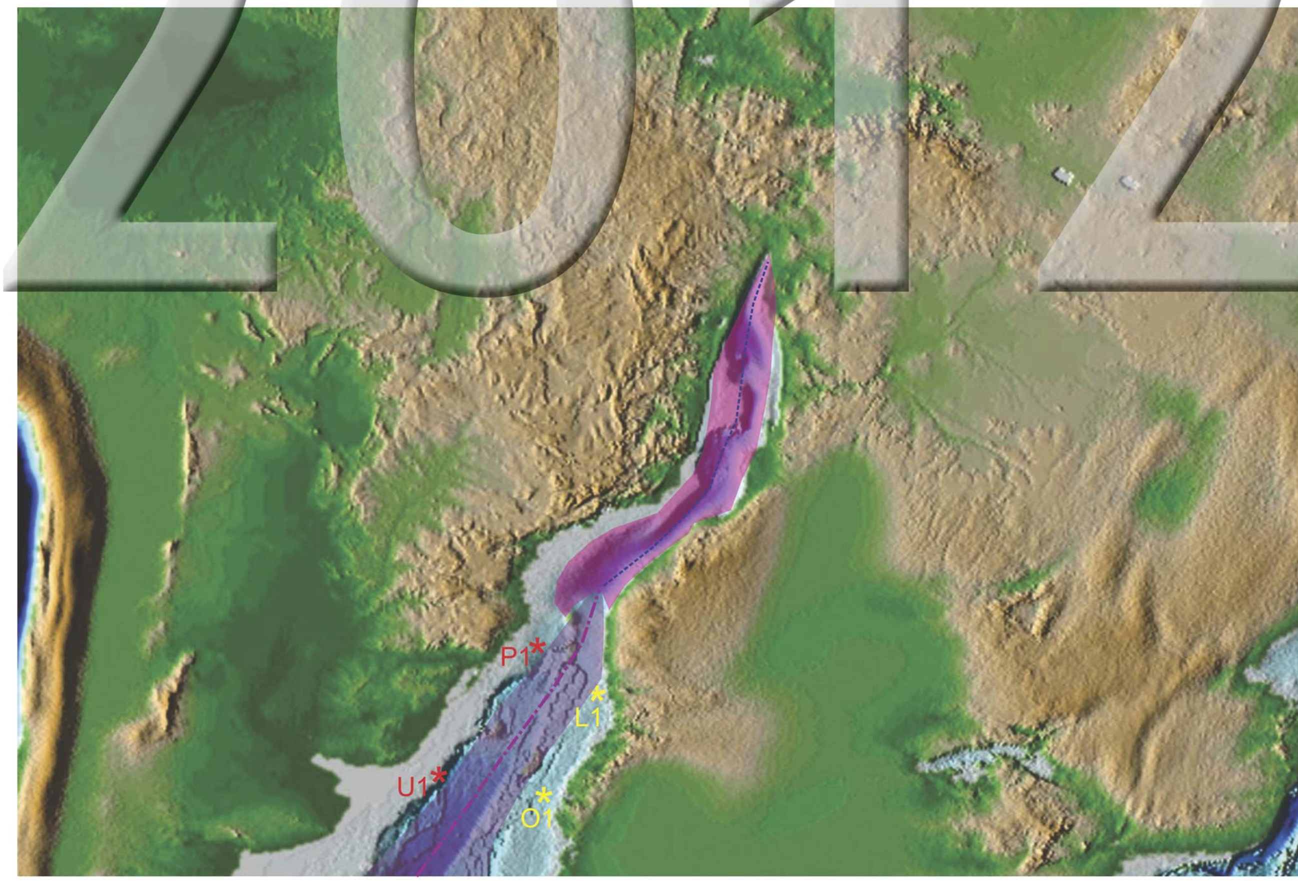
2012



32nd Annual GCSSEPM Foundation Bob F. Perkins Research Conference

December 2-5, 2012, Houston, Texas

New Understanding of the Petroleum Systems of Continental Margins of the World

Editors: Norman C. Rosen, Paul Weimer, Sylvia Maria Coutes dos Anjos, Sverre Henrickson, Edmundo Marques, Mike Mayall, Richard Fillon, Tony D'Agostino, Art Saller, Kurt Campion, Tim Huang, Rick Sarg, and Fred Schroeder

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Program and Abstracts

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GCS FOUNDATION SEPM

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OMNI Houston Westside
Houston, Texas
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Edited by

Norman C. Rosen
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Tim Huang
Rick Sarg
Fred Schroeder

Published December 2012

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Foreword

Continental margins have often played a significant, and sometimes dominant role, in previous Bob F. Perkins conferences. However, the last conference to deal with this geographic area explicitly was in 2000. The advancement in exploration techniques has exploded since then and “new” margins are now in the exploration forefront. The Perkins Conference provides a unique opportunity for such a discussion and dissemination of knowledge. It is small enough, by having only one session at a time, to provide a great deal of interaction. Yet it is large enough to allow participation and input of the local, out-of-state, and the international community.

We have tried to organize the sessions by area, starting off with the Gulf of Mexico, the grandfather of continental margin exploration; then to Australia/New Zealand. We then head east to South America, and then keep moving east to Africa. We then jump back to North America and finish in Europe and Asia. Without question, the Gulf Coast Section has many friends!

In 2008, Kevin Schofield made the following comment in his Foreword:

”In spite of the great sophistication of the technology brought to bear on the collection and analysis of geological data today, particularly in the oil industry, geoscience as practiced by the majority of us remains an essentially empirical endeavor not that different from the science practiced by our forebears in the nineteenth century. They clopped around the country on horseback, collecting samples, comparing and contrasting with their own prior experience and that of others published in the journals of the day. They produced detailed descriptions, maps, and cross-sections, and from these derived theories of how the earth had evolved to its observed state. We travel the globe from our desks, collecting rock samples and remote sensing data of a variety of sorts: seismic, gravity, electromagnetic, and satellite imagery. And, in our turn we compare and contrast with the data of others and develop our own theories or build on those of others to explain how what we observe became so.”

For continental margins, we obviously do not clop around on horses, but the rest of the comments are pretty much still true. No matter how good the technology, nothing can be accomplished without a firm foundation of basic geological principles.

This year, we have been organized somewhat differently. The first idea for a 2012 conference was proposed by Paul Post (thank you). The concept was then expanded to include all continental margins by Paul Weimer, who then assembled the technical cast; not only did he harass them for papers, he flew around the world (supposedly on AAPG business) and found many contributors on his own (thank you). And for better or worse, for the first time, I have been chief editor. After 13 years of harassing the editor-in-chief, I was now able to yell at myself for not getting the papers in to me sooner.

Many thanks to Sylvia Maria Coutes dos Anjos, Sverre Henrickson, Edmundo Marques, Mike Mayall, Menno Dinkelman, and Marek Kacewicz for arranging for papers. Papers need editors and reviewers; these have been Richard Fillon, Tony D’Agostino, Art Saller, Kurt Campion, Tim Huang, Rick Sarg, and Fred Schroeder, and they have my heart-felt thanks for their efforts. Finally, the authors are to be commended for their high-quality ideas and data presented for their talks and posters even though their work loads are exponentially higher than in the past; they also are to be commended on getting the necessary permissions for publication.

This leads into an apology from me for not having the Proceedings ready for distribution at the time of the Conference. It used to be that obtaining permission of publication was a relatively easy task. Now the publication must be completed (often later than expected because of work loads) and then submitted for approval; worse, many partners do not understand the meaning of deadlines for approval.

I say no more.

Finally, as usual, there is a host of characters who have made this conference possible. Gail Bergan has set up the articles for the DVD as well as for the abstract book. Mike Nault has been invaluable in insuring adequate physical arrangements at the conference. Arden Callender is in charge of arranging for the poster boards. I thank them as always. None of this would have been possible without them.

Norman C. Rosen,
Editor-in-Chief

New Understanding of the Petroleum Systems of Continental Margins of the World

32nd Annual Gulf Coast Section SEPM Foundation Bob F. Perkins Research Conference

Program

Sunday, December 2

4:00–6:00 p.m. Registration and refreshments (by Texas Ballroom: Most activities, including all talks and poster sessions, will take place in the Texas Ballroom. Registration will be by the Ballroom entrance.)

Monday, December 3

7:00 a.m. **Continuous registration and (Coffee and rolls will be available)**

7:45 a.m. Welcome Remarks, Patricia Santogrossi (Chair of the Board of Trustees, GCSSEPM Foundation)

7:55 a.m. Introduction to the Conference, Paul Weimer and Norman Rosen (Conference Co-Convenors)

Session 1—Gulf of Mexico

Tuesday, December 4

7:15 a.m. **Continuous registration (Coffee and rolls available)**

Session 3—South America

8:15 a.m. **Introduction: Paulo Otávio Gomes and Patricia Santogrossi**

10:20 a.m. Coffee Break

11:45 a.m. Lunch: Barbeque buffet (included with registration)

Session 3—South America continued

1:25 p.m. **Introduction: Paulo Octávio Gomes and Patricia Santogrossi**

Session 4—Africa

2:30 p.m. **Introduction: Richard Fillon and Mayall**

2:35 p.m. *West Africa Presalt Exploration: Background and Perspective of the West African "Tupi" Myth* 23
Lottaroli, Fabio; Andreotti, Paolo; Cornaggia, Francesco; and Meciani, Lorenzo

3:05 p.m. Coffee Break

3:30 p.m. *Field-Scale Stratigraphy and Depositional Elements of a Slope Channel System and Implications on Dynamic Behaviour of the Reservoir, A Case Study from Angolan Offshore Margin* 24
Cobos, Luz Sophia; Mayall, Mike; Primmer, Tim; and Rosa, Osvaldo

4:00 p.m. *Deep-Water Angola: Block 15/06: Technology and Ideas to Turn a Risky Challenge into an Exploration Success Case* 25
Mantovani, Marco; Barbieri Arnaldi, Paolo; Brajucha, Riccardo; Lottaroli, Fabio; Nolli, Vilia; and Spadini, Giacomo

4:30 p.m. *Contrasting Depositional Styles on a Slope System and Their Control by Salt Tectonics: Through-Going Channels, Ponded Fans, and Mass Transport Complexes* 26
Jones, Gemma; Mayall, Mike; and Lonergan, Lidia

5:15—8:00 p.m. Fajitas, chips, drinks, and poster sessions (reminder: posters must be removed by ~8:15 p.m.)

Wednesday, December 5

7:30 a.m. **Continuous registration (Coffee and rolls available)**

Session 4—Africa continued

8:00 a.m. **Introduction: Tony d'Agostino and Marek Kacewicz**

8:05 a.m. *Evolution of the Reservoir Interpretation and Impact of Interpretation Uncertainties in a Channelized Turbidite Field, Block 31, Angola* 27
Smith, Claire; St. Clair, Krystel; Salazar, Pablo; and Reid, Paul

8:35 a.m. *Offshore Southern Oman: New Insights into the Petroleum Potential of the Northeastern Margin of the Gulf of Aden* 28
Harker, Stuart

9:05 a.m. *Evolution of a Pliocene Upper Slope Channel Complex Set, Giza Field, West Nile Delta, Egypt: Interaction of Sedimentation and Tectonics* 29
Butterworth, Peter and Verhaeghe, Jona

9:35 a.m. *Review of Petroleum Systems and Hydrocarbon Plays of the Levant Margin, Offshore Israel* 30
Gardosh, Michael A.

10:05 a.m. Coffee Break

Session 5—North America

Session 6—Europe/Asia

Session 7—General Topics

Poster only (Monday and Tuesday nights)

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Cover Image

The cover image chosen for this year's conference is Figure 2 from Mohriak *et al*.: "Tectonic Reconstructions and Petroleum System Correlations in the Southern South Atlantic: Exploratory Analysis and the Search for a New Hydrocarbon Play."

North American Offshore Resource Potential and Operating Environment: Prize Versus Challenge Versus Cost

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Abstract

Defining raw resource potential is only the first step in a decision process that, as it evolves, pits technical risk against reward as geological concepts are tested and drilling capabilities are challenged in the drive to deliver hydrocarbons in a safe and environmentally friendly manner, in what are becoming increasingly hostile and costly environments. To take on such challenges the prize must be substantial.

The most recently published government figures (MMS, 2006) for undiscovered technically recoverable reserves estimate that the OCS (offshore continental shelf) of the Gulf of Mexico holds 52% of the remaining oil in the offshore USA. Indeed the 45 BBO (billion barrels oil) mean estimate for the Gulf of Mexico combined with 27 BBO mean estimate for the OCS of Alaska, of which 23 BBO are estimated in the Arctic basins of the Chukchi and Beaufort Seas, make up 83% of the undiscovered conventional offshore oil resources in the USA. Similar studies by the USGS estimate that 28% of the remaining technically recoverable oil resources in Canada are located in the Arctic Beaufort Sea, the Canadian East Coast Basins, including the Labrador and West Greenland conjugate margins. Based on these published estimates the total mean undiscovered recoverable oil reserves in the offshore areas of North America that fall under the exploration remit of the Statoil North America business unit is in the range of 50–80 BBO. The rapid growth of Statoil in North America reflects our belief that the offshore, deep-water margins of North America offer a significant prize that will help Statoil reach its objective of developing into a leading global exploration company that can deliver production above 2.5 million BOED by 2020.

Presently Statoil is one of the major lease holders in the deep water Gulf of Mexico, possessing a portfolio that covers multiple geological plays and extends from the Wilcox deep-water play in the western Gulf through to the Norphlet dune play and Mesozoic carbonate margin plays of the eastern Gulf. In the Grand Banks area of the east coast of Canada, Statoil has increased its acreage position by an order of magnitude in the last two years as a consequence of the Mizzen discovery in the Flemish Pass. In the North American Arctic, a similar growth pattern is seen as Statoil has, by means of lease sale activity, taken a position in the Chukchi Sea and, through farm-in activity, the Canadian Beaufort. Having a strategy focused on early basin access at scale, development and application of technology and skills, and fast track drilling of impact wells Statoil has developed a strong position in North America's offshore basins as it strives to grow towards its corporate ambitions as a leading global exploration company

But to fully assess the potential of such a wide range of opportunities requires more than just sound geological models and finding common denominators across such a diverse area is difficult; deep water may be the only ever present feature. Beyond that, differences in geology, geography, climate/environment, and local regulatory conditions present many, and often significant, challenges. To realize the potential of the offshore basins of North America a number of challenges must be met:

- Climate and environment: from tropical storms and hurricanes in the Gulf of Mexico to sustained summer fog in Canada, to ice movement in the Arctic,
- Regulatory and permitting: balancing technical work and data acquisition with well planning and permitting strategies within limited lease periods
- Drilling and technical: ability to drill successful and safe high pressure and high pressure/high temperature wells in deep-water and Arctic environments

- Geophysical: requirement for more sophisticated seismic acquisition, processing, and imaging strategies to increase image quality in complex geology and provide higher resolution in more conventional geology
- Geological: complex velocity fields, such as those seen in the deep water Gulf of Mexico, required impact data frequency and amplitude ranges so that the data are unsuitable for reservoir definition and characterization, creating increase production uncertainty.

With challenge comes cost. More sophisticated seismic acquisition strategies means a significant increase in cost. Furthermore the complexity of the geology in areas such as the deep water of the Gulf of Mexico requires significant reimaging efforts post-delivery of spec data. This is not just a monetary cost but is also an opportunity cost in such a competitive basin, where yearly lease sales see significant acreage turnover and the fidelity of the image can impact not only whether a bid is made but also the size of bid.

At a larger scale safe drilling operations in the deep water requires access to modern 5th and 6th generation semisubmersible and Enterprise class drill ships, which in a competitive market need to be tied to medium or long term contracts to ensure availability to execute drilling strategies. Emergency, hazard, and response measures are also a requirement for operations and depending on location and environment this can have very difficult cost implications for a project. In the Gulf of Mexico, the Marine Well Containment Corporation provides a number of operating companies with a long-term solution for containment and well control services. In the Arctic no such corporation exists and to meet government regulations a requirement for a stand-by rig to undertake relief operations means that operators need to develop joint drilling strategies or shoulder the extra cost of a second rig within their project economics. The situation in areas such as the Beaufort Sea which are ice-locked for large periods of the year can be even more expensive as there are few qualified ice-class drill ships and the drilling and open seaway seasons for conventional rigs are short, such that mobilization and demobilization costs are significant.

Despite these challenges and costs, Statoil has made a commitment in accessing the offshore basins of North America and is currently drilling a number of impact prospects. As part of the overall exploration strategy, research and technology initiatives have been put in place that are designed to increase our ability to predict basin sweet-spots and define impact prospects, with the goal of increasing drilling success. Execution of these initiatives within that strategy also increase access success, as improved data and concepts lead to better geological models, understanding, and ultimately successful lease sale results; as seen in the 2011 East Coast Land sale in Canada and the 2012 CLS 222 in the Gulf of Mexico.

Over the last eleven years Statoil has returned as a significant offshore exploration force in North America, However, it will be the coming decades that reveal the merit and worth of our effort and strategy as we test our current portfolio, increase our knowledge, and adapt and develop new portfolios based of our increasing experience.

Mexico: State of the Exploration for Oil and Gas

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Abstract

Of all the countries in the world considered to be oil rich, Mexico is the only one that consistently has been losing production and reserves in the last ten years. Even though Mexico has five major producing provinces: two for oil (the Southeast and the Tampico–Misantla basins) and three for gas (the Sabinas, Burgos and Veracruz basins), and has seven more with potential, (California, Gulf of Cortès, Chihuahua, Sierra Madre Oriental, Sierra de Chiapas, Progreso shelf, and the deep Gulf of Mèxico), its output and reserves have declined consistently.

Many reasons can be attributed for these results, and as this note proves, least of them is the country's endowment of oil and gas resources. The problem is that Mexico, since 1938, has had only one oil company responsible for all of its upstream activities and even though Pemex's performance is comparable with that of most of the majors' (it is world's third largest in terms of production), it is impossible that all the remaining potential of the entire country can be found and produced with only one company, no matter how large, wealthy, efficient, technologically advanced, and successful it can be.

The good news is that once the country opens up for third-party participation in exploration, which will eventually take place, results are going to be spectacular. So far there has only been a timid opening for development and exploitation opportunities.

Straining at the Leash: Understanding the Full Potential of the Deep-Water, Subsalt Mad Dog Field, from Appraisal through Early Production

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Abstract

Mad Dog is a giant, subsalt, deep-water oil field that will be producing hydrocarbons for the co-owners BP, BHP Billiton Petroleum, and Chevron in the Gulf of Mexico for many years to come. The field was discovered in 1998 by the GC0826#1 well and sidetracks. Four appraisal wells proved up a material resource but also showed evidence of compartmentalization and imperfect subsalt seismic imaging. A spar development was selected and first oil was achieved in 2005. Further appraisal drilling continued from the spar rig and MODUs, ending with the Mad Dog North appraisal program in December 2011. The original spar rig was lost during Hurricane Ike in September, 2008, and a rig replacement project is currently underway. In 2009, the Mad Dog South appraisal well proved up large volumes of hydrocarbons beyond the drilling radius of the original spar rig, necessitating the construction of a second production facility.

Mad Dog hydrocarbons are predominantly contained in deep-water turbidite sandstones of early Miocene age that can be correlated over hundreds of square miles. The turbidites are interpreted as a series of individual lobes in a submarine fan complex that was deposited in an unconfined basin floor environment. Deformation of the rocks commenced shortly after deposition and continued through the Plio-Pleistocene boundary. The reservoir is divided into several large compartments that are identified by differences in pressure, fluid composition, and oil-water contacts. These large compartments are interpreted to be bounded by seismically visible faults. Smaller seismically visible and subseismic faults act as baffles to fluid flow in the field, and have been identified through logs, dynamic data, and reservoir simulation.

The phased development of the Mad Dog Field has enabled BP and co-owners to mitigate project risk during full-field development. By starting small, developing the known hydrocarbons, investing in technology to improve the imaging of the field, and continuing appraisal drilling, the team was able to evaluate the resources while simultaneously unlocking their value. The integration of dynamic production data with the improved seismic image and appraisal well results has allowed the second phase of the development to proceed with significantly reduced subsurface uncertainty. This has enabled the team to unleash the full potential of the Mad Dog field to be a large deep-water producer for the next 40 years.

21st Century Atlantis–Incremental Knowledge from a Staged-Approach to Development, Illustrated by a Complex Deep-Water Field

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Abstract

Atlantis Field represents a significant development for BP and co-owner BHP Billiton in the southern Green Canyon area of the Gulf of Mexico. With primary development from three middle Miocene sands, it is one of BP's largest fields in the deep water Gulf of Mexico.

Discovered in 1998 and first production in 2007, Atlantis Field was developed in stages from a sub-sea drill center to a remote production facility. A second subsea drill center, centered on an early appraisal well, was connected in mid 2009. Drilling of water injection wells commenced in 2009 following initial dynamic data learning. Additional field development via appraisal drilling is planned for 2012, and two dynamically positioned semi-submersible rigs are currently active in the field.

Located approximately 120 miles (190 km) south of Fourchon, Louisiana, Atlantis Field is a faulted, elongate asymmetric doubly-plunging anticline within the Atwater Fold Belt. Water depths range from 4500 to 7000 feet (1370 to 2070 m) across the field, influenced by the Sigsbee Escarpment, a region of steep sea floor dip created by a thick allochthonous salt complex that partially overlies the structure. Both the allochthonous salt and the significant sea floor relief create challenges in seismic imaging, field development, and have influenced the staged approach.

The producing reservoirs are middle Miocene deep-water turbidites interpreted as a series of individual lobes in a submarine fan complex that were deposited in a relatively unconfined basin floor environment. Deformation of the reservoir commenced shortly after deposition and is dominated by the formation of the Atwater Fold Belt and culminated with the later partial burial of the structure by the thick allochthonous salt canopy. The reservoir was interpreted to be compartmentalized, based on the seismically defined faults, and these compartments were confirmed by static pressures. However, production data now indicate a greater reservoir compartmentalization beyond that initially defined. Data acquisition in new wells is targeted to understand further the reservoir deformation and stratigraphic complexity that negatively impacts permeability, acting as barriers or baffles to fluid flow.

Immediate and Postevent Effects of the K/Pg Boundary Chicxulub Impact on the Northern Gulf of Mexico

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Abstract

The Chicxulub bolide impact on the Yucatan peninsula at the Cretaceous-Paleogene (K/Pg) boundary has been postulated as the trigger that remobilized sediment into mass transport flows on the submerged shelf along eastern North and Central America as well as around the Gulf of Mexico and redistributed sediment out into the deep water Atlantic, Caribbean, and Gulf of Mexico. Well log and biostratigraphic data from Cretaceous well penetrations in the deep-water northern Gulf of Mexico show a distinctive micritic deposit at the K/Pg boundary that is similar in composition and biostratigraphy to sediments found near the Chicxulub crater, DSDP/ODP cores, and outcrops in Cuba. Investigation of seismic data in the northern Gulf of Mexico shows anomalous sedimentary wedges of high amplitude reflectors situated at the top of the Cretaceous section that are interpreted to be the resulting deposit from the mass transport flows and suspension fallout initiated by the impact.

At the end of the Cretaceous, the northern Gulf of Mexico was undergoing allocthonous salt movement from the Jurassic Louann Salt that was expressed in numerous salt highs defining potential clastic sediment fairways. The sediment redistribution caused by the Chicxulub impact filled in the available accommodation space around the salt highs, as well as depositing on the highs themselves, and altered the seafloor topography across the northern Gulf of Mexico. This resulted in an efficient transportation pathway from shelf to deep water and influenced the sedimentation patterns of the subsequent sediment gravity flows of the Wilcox Formation.

Petroleum Geology of the Mississippi Canyon, Atwater Valley, Western Desoto Canyon, and Western Lloyd Areas, Northern Deep Gulf of Mexico: Traps, Reservoirs, and Their Timing

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Abstract

The petroleum geology of the Mississippi Canyon, Atwater Valley, western DeSoto and western Lloyd Ridge protraction areas, offshore northern Gulf of Mexico, is controlled by the interaction of salt tectonics and high sedimentation rate during the Neogene, and has resulted resulting in a complex distribution of reservoirs and traps. Seventy-eight fields/discoveries are evaluated and comprise structures with four-way closures (18), three-way closures (46), and stratigraphic traps (14). Three of these discoveries are in Upper Jurassic eolian reservoirs, the remainder are in Neogene deepwater reservoirs.

The tectonic-stratigraphic evolution of the area is analyzed at eleven discrete intervals between 24 Ma and Present. The analyses show how the allochthonous salt systems evolved over time, and their effect on sedimentation patterns and sub-basin evolution.

The study area includes some of the largest fields in the northern deep Gulf of Mexico. Thunder Horse produces from an anticlinal (turtle) structure that developed with a basement-controlled allochthonous system. The greater Mars-Ursa sub-basin has nine fields with > 1.5 BBBOE EUR, including Mars, Ursa and Princess, that developed with a counterregional allochthonous salt system. The remaining fields have considerably smaller reserves, which are controlled by the area within closure and number of reservoir intervals. Many of the smaller fields are produced from one well subsea tiebacks.

Most of fields in the study area are contained within sheet-like or wedge-shaped stratigraphic intervals and have four-way or three-way trapping configurations. These findings reflect the profound effect that mobile salt has had on the petroleum geology of the region.

The Aspen Basin: A Case Study in the Integration of Biostratigraphy, Core Analysis, Depositional Models, and Production Data for the Purpose of Understanding Reservoir Architecture in a Deep-Water Sheet Sand System

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Abstract

Predicting the lateral continuity, vertical connectivity, and compartmentalization of deep-water reservoirs is critical to both their understanding and producibility. The Aspen Field, located in Green Canyon block 243 at a water-depth of 2,723 feet (Fig. 1), consists of a series of upper Miocene (Rob E) stacked hydrocarbon-bearing sands that are currently under production. Conventional core from the L Sand (main producing interval) displays two primary depositional facies: (1) thickly bedded to massive, weakly consolidated, fine-grained sands that represent amalgamated sheets deposited along the axis of flow and (2) finer grained, medium bedded, layered sheet sands deposited along flow margins. These facies reflect deposition in a distributive deep-water system (Fig. 2).

The Aspen Field data set provides an opportunity to address three key challenges to our understanding of deep-water reservoir systems in the Miocene of the Gulf of Mexico: (1) what is the lateral continuity of an important reservoir sand, (2) what types of vertical compartmentalization exist in a distributive, sheet sand system, and (3) how does the alteration of volcanic rock fragments (mainly volcanic glass) and the precipitation of clinoptilolite as a cement affect reservoir quality. Through the combination of multiple rock data sets (conventional cores, sidewall cores and well cuttings), high-resolution biostratigraphic analysis, and production data an integrated geologic model has been constructed to characterize the detailed reservoir complexity encountered at Aspen and relate that complexity to well performance.

High-resolution biostratigraphic analysis was applied to all wells in the Aspen Field to help subdivide reservoir packages and delineate sand-body architecture and stratigraphic pinch-outs. This methodology utilizes standard biostratigraphic information (i.e. regional extinction events, paleoecology, and abundance/diversity profiles) coupled with coiling direction reversals (*i.e.*, *G. menardii*, *G. humerosa*), size changes (*i.e.*, *G. menardii*), individual abundance increases (*C. mexicana*), and local fossil increases in order to define local biomarkers instrumental for field-scale correlation. Four regional biostratigraphic markers were initially defined around the Aspen pay interval providing a general biostratigraphic framework for the field (Fig. 3). The application of high-resolution biostratigraphic analysis not only confirmed regional and semi-regional flooding surfaces (marker horizons) in a lower bathyal setting but identified additional local field-scale events between the regional and semi-regional surfaces (Fig. 4). To-date, the long-term production and reservoir simulation have validated this reservoir architecture.

Interpretation of MDT pressure, well log, seismic, seal and lithologic data used in conjunction with high-resolution paleontological data have established

multiple reservoir levels that occupy separate pressure regimes. MDT pressure data clearly demonstrate significant reservoir compartmentalization between the various sands at Aspen caused by the distribution of claystone packages occurring at the top of third-order depositional sequences (Fig. 5). Mercury displacement entry pressure data ranges from 1,900 to 3,000 psi and indicates that the capping claystones have effective seal capacity. This equates to a maximum calculated hydrocarbon column of 886 feet for the K Sand, 792 feet for the L Sand, and 670 feet for the M Sand. MDT pressure data also show pressure compartmentalization within the L Sand interval, suggesting that some of the thinner (higher-order) claystones are also effective seals (Fig, 5). An excellent analog for these hierarchical scales of reservoir compartmentalization can be found in the Pennsylvanian Jackfork Group of Arkansas, where similar claystone facies are observed in both inter- and intrasheet sand positions (Fig. 6).

Diagenesis is an additional complication in reservoir characterization at the Aspen Field. To determine its effects on the reservoir, core was collected in zones thought to be impacted by diagenesis. An analysis of thin-sections created from core showed that tuffaceous, volcanic rock fragments and glass shards are common constituents in the Aspen reservoirs (Fig. 7). An additional component was the zeolite clinoptilolite $[(Na,K,Ca)_2\text{-}_3Al_3(Al,Si)_2Si_{13}O_{36}\text{-}12H_2O]$, which precipitated as a result of devitrification of volcanic constituents. Clinoptilolite crystals ranging from 3 to 30 microns in size were dispersed in varying degrees throughout the pore system and significantly reduced inter-granular pore volume (Fig. 8). Clinoptilolite abundance ranges from 4 to 19 wt. % by X-ray diffraction techniques with an average of 9% (n = 44) and is observed in all samples of the Aspen L Sand.

The presence of clinoptilolite cements can have a number of effects on formation evaluation including: (1) a lowered resistivity tool response due to elevated capillary water, high cation exchange, and the presence of water in the mineral matrix; (2) an optimistic density porosity evaluation that fails to account for clinoptilolite's low (2.1–2.2 gm/cc) matrix density; and (3) a significant decrease in permeability (Fig. 9). In addition, a major production problem can occur due to the migration of clinoptilolite and other fines into pore throats. This problem may be significantly exacerbated by producing at high flow rates or by significant perturbations to the production rate (as may occur during unexpected shut-ins and restarts).

In summary, an understanding of the lateral continuity, vertical connectivity, distribution of sealing facies and diagenetic overprint of deep-water reservoirs is critical for an accurate assessment of their producibility. Sheet-sand reservoirs are often thought of as relatively uniform in their stratigraphic correlation and flow characteristics; however, this example gives evidence to the contrary. The Aspen Field dataset provides a robust example of the complexity of sheet-sand reservoirs from pore to bed-set scale and underscores the importance of data integration from multiple sources to accurately characterize reservoir architecture and quality.

Initial Evaluation of Structural and Stratigraphic Compartmentalization in the Pony-Knotty Head Field, Green Canyon, Deep-Water Gulf of Mexico

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Abstract

Reservoirs at Pony-Knity Head Field consist of stacked, middle Miocene (Serravallian) turbidites deposited as high-frequency low-stand successions within an increasingly ponded basin. Depositional elements include: (1) high to moderate permeability channel axes, channel margins, channelized lobes, and amalgamated lobes; and (2) those having low-permeability, such as marginal to distal lobes, levee-overbank debrites, slumped muds/ heterolithics, and pelagic/ hemipelagic muds. Fluid pressure data demonstrate that the Pony - Knotty Head Field is segmented into pressure compartments at multiple scales.

Although the field is a low-dip, faulted, four-way turtle structure, interpreted faults are neither long enough nor have sufficient throw to segment reservoirs into observed pressure cells. Analyses of individual reservoir units indicate that variations in fluid potential are often greater vertically within wells than laterally between wells. This pattern indicates that at least some segmentation at this scale is due to low-dip stratigraphic barriers between depositional elements rather than to steeply dipping barriers, such as faults.

At the field scale, both fluid pressures and depositional elements change vertically. Excess pressure was used to help define compartments at Pony-Knotty Head Field. ("Excess pressure" is the difference between pressure measured in a well and pressure calculated using a datum with an expected fluid gradient.) The deepest reservoirs have the lowest excess pressures. They are dominated by laterally continuous, unconfined depositional elements that bled excess pressure laterally. Progressively shallower reservoirs have progressively higher excess pressures in progressively more confined depositional elements. Between reservoirs of different depths and ages, stratigraphic complexity increased with time as increasing structural confinement of the depocenter above mobile salt drove stratigraphic evolution from a lobe-dominated system to a channelized lobe and levee-channel complex system. We propose that compartmentalization at this scale results directly from stratigraphic responses to the structural evolution of depocenters.

Context, Challenges, and Future of Deep-Water Plays: An Overview

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Abstract

In recent years deep-water petroleum exploration has been booming. The Gulf of Mexico, some West African regions, and Brazil are leading this growing activity. Current deep-water plays focus on presalt, subsalt, stratigraphic pinch-out and deep-water folded belt targets. Comparisons of conjugated margins across the Atlantic are commonly used by explorationists to extend the prospectivity of known plays. However, what are deep-water plays? Are they only plays presently located in water depths more than 2000 m water depths or do they also include plays developed initially in relatively deep oceanic tectonic settings but are now underneath shallow water? For that matter, what about plays which developed in relatively shallow water but are now located in water depths greater than the continental slope.

Present deep-water tectonic settings are mostly compressional toe-thrust regions of larger massive gravitational collapses related to (A) major deltas (B) allochthonous salt provinces, or (C) subduction-related accretionary wedges. Back-arc extensional basins in deep-water settings are underexplored, except for the Black Sea. Other plays presently in deep waters but from a geologic perspective initially formed in relatively shallow marine water and subsequently subsided are the pre-evaporitic plays of the Campos-Santos basins in Brazil and Angola offshore basins.

Some elements of deep-water petroleum systems are still poorly understood. Although the presence of widespread deep-water source beds on oceanic crust is mostly known through DSDP/ODP wells, the role of tectonics and volcanic activity in the generation and maturation has yet to be adequately evaluated. Classical upwelling models intended to explain marine source beds may need to be refined.

Note that most current deep-water-plays involve siliciclastics. There is no reason to preclude deep-water carbonate plays, the reservoirs of which are analogous to the outer platform, relatively deep-water pelagic carbonates producing in the Bay of Campeche in Mexico.

Traditional seismic stratigraphy views unconformities as being caused by eustatic sea level changes. However, the origin of widespread deep-water unconformities needs to be further elucidated.

An increasing number of deep crustal seismic surveys along West Africa show low-angle extensional detachments similar to those found on the Galicia margin of Spain and Portugal and comparable with tectonic styles of the Basin and Range Province of the western United States or else in the western Mediterranean (*e.g.*, Western Alps or Betic Cordillera). Classical rifting models always need to be updated to be “on target” with new and often surprising seismic observations. In addition to the four principal types of deep-water plays currently being explored, additional plays should be found in deep-water carbonates, volcanic margins including hot spots or volcanic-lineaments, and subsided rifted systems; these may account for significant yet to be explored future plays in many parts of the “deep-water” world.

Seismic Stratigraphy of the Reinga Basin, Northwest New Zealand: Tectonic and Petroleum Implications

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Abstract

The Reinga Basin occupies a northwest-southeast bathymetric d epression between the West Norfolk and Reinga ridges and has an area of about 100,000 sq. km. Rock samples have been dredged from surrounding ridges, but no boreholes have been drilled. We present a seismic stratigraphy developed using 5,135 line km of new 2D seismic-reflection data and 20,000 line km of older data, and we tie this stratigraphy to boreholes in the nearby Northland and Taranaki basins. We identify six phases of basin evolution. The first phase involved extension across northwest-trending normal faults. The region subsided passively during phase 2, and we infer from regional considerations that this phase lasted from Late Cretaceous until middle Eocene time. Phase 3 was late Eocene compression, which we interpret to be related to the initiation of the Tonga-Kermadec subduction. This led to uplift and erosion of the West Norfolk and Reinga ridges and deposition of detrital material at the center of the Reinga basin. Oligocene to early Miocene regional subsidence (phase 4) resulted in flooding of structures created during phase 3. Uplift of the Wanganella Ridge, in the northwest part of the Reinga Basin, occurred at the end of the early Miocene (phase 5). The last phase is tectonically passive, but with ongoing sedimentation up until the present day (phase 6).

Upper Cretaceous units in the nearby Taranaki Basin contain coaly source rocks, and coal has been dredged from the ridge on the southwest margin of the Reinga Basin. Maturation models of three sites in the Reinga Basin predict that Cretaceous type III coaly source rocks within basal strata would begin to generate and expel petroleum in early Cenozoic time and expulsion would continue to the present day. The top of the oil expulsion window is modeled at 4.0 +/- 0.5 km below the sea bed, implying a potential kitchen area of approximately 15,000 sq km for Cretaceous source rocks, or a broader area if Jurassic source rocks are present. Most oil and gas expulsion is predicted to be later than the Eocene to Miocene folding and reverse faulting events that created structural traps. It is outside the scope of our study to develop play concepts or analyze direct hydrocarbon indicators, but our regional stratigraphic and tectonic study, combined with a consideration of petroleum system components that may be present, indicates that the Reinga Basin is prospective for oil and gas.

Exploration of Contemporaneous Delta and Deep-Water Deposits: Berriasian Lower Barrow Group, Exmouth Plateau, North Carnarvon Basin, Australia

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Abstract

An active exploration campaign in the Exmouth Plateau has yielded gas discoveries in a coeval wave-influenced delta and deep-water, sand-rich fan succession. Depositional elements were organized into clinoform seismic stratigraphic units that blanketed irregular topography created by extensional tectonics. Clinoform geometries revealed steady, rising and falling shelf-slope break trajectories. Slope successions associated with rising trajectories were devoid of deep-water feeder systems. In contrast, during steady to falling trajectories, the slope was characterized by numerous gullies. These gullies served as the main delivery system for sediment gravity flows into the basin. In some instances, an individual gully dominated and captured the flows of subordinate gullies and developed into a larger feeder system. The feeder systems were self-sourced and cannibalized the deltaic and slope successions through knickpoint retreat.

Arcuate strandplains organized into wave-influenced cuspate lobes characterized the deltaic succession. Littoral drift was locally to the east. Delta front well information indicated excellent reservoir quality. Sedimentological analysis of core data indicated different depositional processes as a function of the clinoform geometries. High quality delta front sands were fed into the slope and basin floor as sediment gravity flows and deposited as coalescing sand-rich fans. The fan cores were composed of high-density turbidites that graded into debrites and linked debrites along the margins. The deep-water fans were of favorable to excellent reservoir quality.

Characterization of Channels in the Mungaroo Formation, Exmouth Plateau, North Carnarvon Basin, Australia

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Abstract

The late Triassic Mungaroo Formation is a prolific gas-condensate reservoir along the landward margins of the Exmouth Plateau (*i.e.*, Gorgon and Rankin trends). Recent exploration drilling has stepped outboard of these trends into the Exmouth Plateau adding calibration to an area of sparse well control. Reservoir units were primarily channelized complexes of variable widths and orientations within a large fluvial-deltaic complex that formed a thick (>2.5 kilometer) succession. Channel complexes were attractive exploration targets and have been the reservoirs of recent discoveries.

Mungaroo channelized complexes were thick >10 meters, multistorey, and greater than 1 kilometer in width. Their depositional origins were considered either distributaries or channels within an incised valley. Reservoir characterization studies has provided ranges in the properties of the channels, internal reservoir architecture and expected facies distribution that allowed for gas initially in place (GIIP) and estimated ultimate recovery (EUR) calculations.

Tectonic Reconstructions and Petroleum System Correlations in the Southern South Atlantic: Exploratory Analysis and the Search for a New Hydrocarbon Play

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Abstract

Plate tectonic reconstructions and geophysical interpretations across the southern South Atlantic Ocean suggest geodynamic relationships between Brazilian and West African continental margin basins, particularly the correlation of synrift basins, transform faults, fracture zones, salt basins, and other geological markers. The analysis indicates a diversity of basin characteristics (rift and drift systems) on both sides of the South Atlantic that define them as different stratigraphic, structural, and geochemical entities. Marked differences are observed between the basins north and south of the Florianópolis (Rio Grande) Fracture Zone in Brazil and the Walvis Ridge in Africa, which are clearly expressed in the regional deep seismic profiles recently obtained in the conjugate margins. However, in terms of petroleum systems, the basins are characterized by several geochemical similarities in source rocks deposited during a continental, lacustrine synrift sequence.

This interpretation has been overlooked by several previous works comparing the South Atlantic margins, but it has been recently applied to the delineation of several exploratory targets in the southern Angola, Namibian, and South Africa offshore basins. Two end-end member basins have been suggested north and south of the Walvis Ridge–Florianópolis Fracture Zone, which experienced a different structural and stratigraphic evolution as a consequence of their geodynamic models. The southern African basins (located south of the Walvis Ridge), as well as the conjugate Pelotas Basin offshore Brazil, and the offshore Uruguay and Argentina basins, have been associated with the development of volcanic margins, formed during the emplacement of the Tristan da Cunha mantle plume. Due to the lack of significant hydrocarbon discoveries in the southernmost South Atlantic, doubts have been cast on the presence of the prolific Lower Cretaceous lacustrine source rock systems south of the Walvis Ridge, which occur in the northern basins (particularly in the Greater Campos basin) and are overlain by the massive salt offshore Angola. This work reports the comparison of the geological, geophysical, geochemical and consequently the petroleum system features of the Namibian and South African basins (Walvis, Lüderitz, and Orange) with the basins offshore Brazil, Uruguay, and Argentina.

The results of seismic, potential field, and geochemical analyses of oil samples recovered from offshore wells in the South Atlantic conjugate margins endorse the application of a unified model for source rock and petroleum system assessment in the offshore basins, heralding the existence of a new frontier for the petroleum exploration offshore Namibia, possibly containing giant lacustrine oil and gas reserves.

Main Trap Models of OGX’s Oil Discovery from Albian/Cenomanian Carbonate Reservoirs—Cabo Frio High, Southern Campos Basin

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Abstract

The great geological success in OGX´s oil prospecting at the Albian-Cenomanian carbonate shelf on the southern Campos basin involves at least three different geologic components: (1) the appropriate geographic position of the traps within a low geopressure zone, away from the high pressure oil kitchen (external rift) and beyond the most prolific oil carrier bed of the Campos basin–the Cabo Frio fault system (Papa Terra, Maromba, Polvo and Peregrino oil fields and all of the discoveries made by OGX); (2) the Late Cretaceous and mainly early Tertiary magmatic events that contributed to the generation of an intensive and extensive high secondary porosity and increased permeability by thermobaric effects on the carbonate rocks; and (3) the presence of a high energy carbonate depositional system in the Quissamã Formation (Albian) and Imbetiba Formation (Cenomanian), which involves lateral accretion [*e.g.*, Pipeline (1-OGX-2A-RJS well), Waimea (1-OGX-3-RJS well), Etna (1-OGX-6-RJS well), Fuji (1-OGX-8-RJS well), Illimani (1-OGX-28D-RJS well), Peró (1-OGX-14-RJS well), and Tamborá (1-OGX-52-RJS well)] and vertical stacking [*e.g.*, Waikiki (1-OGX-25-RJS well)] of thickening and shoaling upward carbonate depositional cycles.

The oil accumulations in the Quissamã Formation are well defined by logs and pressure data (Pipeline, Etna, Illimani, Fuji, Waimea and Tambora wells) and are typically related to five tilted fault block trends (faults strike direction northeast/southwest), subparallel to the Cabo Frio fault system, all of which are filled to the spill-point, and each has a different oil/water contacts. As a general rule the antithetic faults act as the major controlling seal for the oil accumulations in these three-way dip closure structures.

The last successfully tested exploration model was a stratigraphic-structural trap formed by the updip pinch out of prograding carbonate shoals in the Imbetiba Formation relative to regional structural dip. This was drilled by the 1-OGX-14-RJS well (Peró Prospect) with an oil column of approximately 60 m based on pressures and well log data.

Work Flow for Geological Characterization and Modeling of the Albian Carbonate Reservoirs from Offshore Campos Basin, Brazil

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Abstract

Recent and very important oil discoveries in Albian carbonate reservoirs from the shallow to deep waters in the marginal basins off the eastern coast of Brazil have led Petrobras to develop work flows for the geological characterization and modeling of these complex reservoirs. The Albian carbonate reservoirs are often elongated shoals that are mainly composed of grainstones and packstones containing oncolites, peloids, oolites, and rare bioclasts. The sedimentation occurred in a high temperature hypersaline environment (Spadini *et al*., 1988). The geological controlling factors on reservoir quality are different in each of the Albian fields. Blauth (1993) and Blauth and Carvalho (1994) document the effect of depositional and diagenetic features on pore geometry and permeability of the Albian carbonate reservoirs of the Santos Basin, Brazil. Guimarães (1995) gives a complete reservoir characterization and geostatistical modeling of an Albian carbonate reservoir from the Campos Basin in his master's degree.

Santonian-Campanian Channelized Systems of the Santos Basin, Brazil: Stratigraphic Framework and Reservoir Potential

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Abstract

Three-D seismic and well data enabled the high resolution interpretation of a Santonian-age succession in present day shallow waters of Santos basin, Brazilian east continental margin, where recent oil and gas discoveries have been made by OGX Oil & Gas. An organized hierarchical system of depositional sequences was identified. A lower order composite depositional sequence was interpreted from seismic facies, lithofacies distribution and bio-chronostratigraphy. The composite depositional sequence was broken down into its constituent systems tracts, each of them exhibiting characteristic patterns in seismic and well log data. Comprising the lowstand systems tract of the composite depositional sequence are five stratigraphic levels of sandy deposits intercalated with thick hemipelagic shale drapes which constitute the elementary depositional sequences of this systems tract. The sandy deposits are mainly erosion-confined channels and/or channel complexes that increase upward in both size and net sand content, reflecting the increasing energy associated with the erosive processes that carved the channels/channel complexes. A capping sequence containing smaller channel complexes with less net sand content reflects the waning depositional energy at the end of the lowstand system. Crucial to understand the distribution and connectivity of reservoirs, establishment of this sequence stratigraphic framework enabled the recognition and correlation of individual sandy deposits in each of the elementary depositional sequences, both spatially and chronostratigraphically.

Contrasting Tectonic-Sedimentary Styles of Deep-Water Systems—Campos Basin, Brazil

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Abstract

This work describes the interaction between tectonic and stratigraphic/sedimentary processes during deposition of the huge deepwater systems containing sandstones reservoirs in the Campos basin (offshore Brazil). These sandstones established a major oil province with about 10 billion barrels of proven recoverable hydrocarbons. An integrated approach, including quantitative petrography, facies architecture, sequence stratigraphy, and tectonic-structural analysis indicates a complex evolution, rather than the previous scenario of gravitational salt tectonics and eustatic base level fluctuations that implies the lowstand paradigm for deepwater sandstones. The marine phase of deposition in the Campos Basin was far from a steady-state, passive margin model.

In general, the main deep-water sand depocenters in the divergent margin phase of the Campos basin were controlled by basement reactivations that triggered successive episodes of salt tectonics, which in turn controlled sand distribution and facies architecture. The first event caused the complete destruction of the Albian carbonate shelf and the formation of a mega-slope during the Late Cretaceous. As a consequence, the main deep-water sand systems show an increase in petrographical immaturity, which corresponds to tectonic reactivation of the basement as they systematically filled and spilled out of depocenters created by basement highs in the offshore Campos basin. The magmatism and dynamic uplift caused by movement of the basin above a thermal anomaly in the mantle are indicated by the anomalously high volcanic contributions in deep-water sandstones, particularly during the Maastrichtian.

Tectonic, magmatic, and structural (upstream) controls on deep-water systems were subdued after the Eocene. Since the late Oligocene, when the shelf was fully reestablished, the classic lowstand systems tract approach predicts quite well the prevalent eustatic processes controlling (downstream control) deposition of deepwater sandstones in the Campos Basin.

Turbidite Systems in the Campos Basin Oligo-Miocene and Miocene, Brazil

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Abstract

The integration of regional 3D seismic, well logs, cores, and biostratigraphic data gathered in a sequence stratigraphic approach provide a basis for interpreting the Oligo-Miocene and Miocene system as a whole. This stratigraphic interval, which contains the most of oil reserves in Campos basin turbidites, was divided into third and fourth order sequences and mapped across the shelf, slope, and basin.

The characteristic depositional geometries recognized in seismic sections are: (1) shelf-edge prograding delta complex; (2) shelf breaching incised valleys; (3) slope erosive bypass zone, which has straight shallow channels and canyons; (4) braided sandy submarine channels filling fault-related depressions and troughs; and (5) asymmetric or elongated sandy turbidite lobes and lobes reworked by bottom currents.

Shelf-edge prograding delta complexes are comprised of granules and coarse- to very coarse-grained sands deposited during the late lowstand systems tract. Common turbidite facies are: (A) extra-formational conglomerates with shallow water bioclasts; (B) structureless medium- to fine-grained sandstones containing dispersed granules and coal fragments; (C) intraclastic sandstones; and (D) fine- to very fine- grained laminated sandstones. Heteroliths are present at the very end of the cycles.

Catastrophic floods related to strongly prograding fluviodeltaic systems caused hyperpycnal flows during sea-level falls are assumed to be the main process responsible for transferring large amounts of sandy sediments to the basin. The denudation of the Serra do Mar uplift supplied the large volumes of sediment required to fill depositional lows related to inherited basement structures and halokinesis, ultimately controlling the accommodation space.

Jubarte Field 3D Modeling Based on the Integration of Outcrop Analogs and Elastic Seismic Attributes

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Abstract

Jubarte is an oil field located offshore of Campos Basin, southeastern Brazil. Discovered in 2001, it is currently the most important oil accumulation of Espirito Santo State. Today, Phase 1 of the development plan has already been implemented and is producing through four one-kilometer-reservoir-exposure horizontal wells connected to FPSO P-34 platform. The field cumulative oil production already has reached 67,000,000 BO, representing around 3% of the total reserve.

Phase 2 of the development plan is ongoing and eighteen new wells are being drilled at the moment. To support well planning, a new version of the 3D geological model, incorporating recent acquired data, is underway. This task has being accomplished by integrating several sources of information. New data coming from the new wells is associated to information from analog outcrops, from interpretation of seismic horizons corresponding to erosive surfaces of turbiditic channels (corresponding to relative sea level falls correlative surfaces), and from inversion of seismic attributes (VP-VS ratio) from a high density 3D (HD3D) cube.

Analog outcrop information comes from the Annot sandstone (Annot Basin, Eocene sequence, France). The vertical shape of facies sequence is inferred based on 3D models from this outcrop as well as the geometry of the channel filling, the vertical proportion curves (VPC), and facies variograms, which work as a complement of well data.

Mapped seismic surfaces were used to separate different channel-filling populations that were modeled as individual regions in geological grid using different VPC, variograms, and global statistics.

A good correlation between the VPC of turbidite-channel-data and Vp-Vs ratio, from elastic inversion performed in the HD3D seismic cube, was observed, making it possible to generate a 3D facies proportion map based on VP-VS ratio, wells, and outcrop data.

The integration allowed a simulation of facies that represents better the existing reservoir heterogeneity.

An Active Petroleum System in Shallow Waters in Eastern Pará-Maranhão Offshore Basin, Brazilian Equatorial Atlantic Margin

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Abstract

Several wells drilled during the 70s and 80s in shallow waters of Pará-Maranhão offshore basin, Brazilian Equatorial Atlantic Margin, discovered Albian to Cenomanian source rocks, good Cenomanian to Santonian reservoirs, and, most importantly, recovered oil. Petrophysical reassessment of those wells using new techniques and knowledge combined with new 3D seismic acquisition methods and interpretation models guided by new theories on the breakup of continental margins, has shed light and improved understanding of the tectono-stratigraphic evolution of the Pará-Maranhão offshore basin and its petroleum system. The breakup of the Brazilian Equatorial Atlantic Margin at the Pará-Maranhão offshore basin occurred during the late Albian (102 Ma). The immediate post-breakup marine transgression over ancient continental areas coupled with the irregular paleotopography inherited from the rift phase created localized ponds and conditions for the source rock deposition.

In the same period, the global geological record registers two anoxic global events, OAE1d (Breistroffer) and OAE2 (Bonarelli). Those two events enhanced the potential for source rock deposition during the early drifting phase in the Pará-Maranhão offshore basin. The new 3D seismic data show features suggesting that after the initial transgressive phase, when the source rock was deposited, recurrent deltaic progradation occurred and delivered sandy deposits on the continental shelf. Seismic imaging (geometry and three-dimensional distribution of the depositional bodies), well data (logs, lithology, biostratigraphy), and paleoecologic interpretation strongly suggest that the sandy bodies deposited on the shelf are turbidities likely fed by the same fluvial system ascribed for the deltaic building.

The subsequent overburden of the drift succession pushed the source rocks into the oil window. The close proximity of source rock to the reservoirs, helped by faults active just after the breakup, represent an exceptional condition for migration and focalization of the hydrocarbon into the reservoirs. Some wells drilled in the analyzed area had oil shows and even have produced oil. However, all of them were classified as non-commercial. The *posteriori* assessment led to two conclusions: (1) the 2D seismic data available at that time precluded good imaging and hence compromised the interpretation of the tectono-sedimentary evolution of the basin and its petroleum system; and (2) the drilling and resource assessment at that time also precluded a conclusive result on the potential of those wells. Nevertheless, new data, techniques, and knowledge available nowadays have enhanced the confidence considering this area as a potential oil province.

West Africa Presalt Exploration: Background and Perspective of the West African "Tupi" Myth

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Abstract

In West Africa, the presalt is an established play since the 1950s. Even so, only recently has the expectations for a potential extension of the Brazilian Santos/Campos basins proven presalt carbonate play boosted spectacular interest in the Kwanza basin (south Angola). The "Sag carbonate Play" has gained most of the attention and promises to be the real "sweet spot" of future presalt exploration, at least in Angola. Moreover, new technologies and ideas allow us to reexamine the great complexity of the presalt play on the historically explored trend (onshore and in conventional waters) along the whole West African margin.

Field-Scale Stratigraphy and Depositional Elements of a Slope Channel System and Implications on Dynamic Behaviour of the Reservoir, A Case Study from Angolan Offshore Margin

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Abstract

During the past decade, in Offshore Angola, great improvements have been made on the imaging of deep-water turbidite slope channel systems through the acquisition of high resolution seismic surveys. In the Marte Field, in Block 31 NE, these have resulted in greater definition of the internal stratigraphy within the third-order channel complexes. Fourth-order channel cuts and fills with associated facies and muddy slumps have been mapped to a greater degree of detail. Better definition of the internal depositional elements also has resulted in the recognition of a higher degree of heterogeneity within the channel systems and implications on the dynamic behaviour of the fluids within the reservoir. Improvements on data quality also have enabled the quantitative use of AVA and inversion products for property population of static models. Given the sparse well data for rock property calibration, the integration of surgical facies mapping as regions within the geocellular models has allowed us to constrain further property population with well and analoge calibrated net-to-gross estimates. Combination of alternate facies descriptions on different polygons have been used to obtain a range of alternate dynamic scenarios and cases. These range of models allow us to establish a reservoir operating envelope that is being used for development well planning and for reservoir management decisions.

Deep-Water Angola: Block 15/06: Technology and Ideas to Turn a Risky Challenge into an Exploration Success Case

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Abstract

Within the Tertiary succession of the Angolan continental slope, turbidite channels and associated levees and lobes have been the target of successful deep water exploration since the early 1990s, establishing several world-class deep water development projects (Bouchet *et al.*, 2005). Block 15 (Fig. 1) played a leading role in this "golden age" of offshore exploration in Angola. Exxon and partners (**eni**, BP, and Statoil) proved more than 3 billion barrels of oil reserves by 19 new field wildcats and 8 appraisals (1997–2003). The Kizomba development growth to more than 550,000 BOED production in 3 years is evidence of the unique prolific nature of these reservoirs.

eni took the challenge of creating value from an extensively explored area and that had already delivered so much by leading the contractor group that took over the portion of Block 15 relinquished by Exxon, now Block 15/06, by agreeing to a heavy work commitment (8 wells, 3D seismic). B15/06 was awarded in December, 2006. The work obligations of the first exploration period were completed 18 months before expiry, exceeding the drilling and seismic commitments. Out of the 10 new field wildcats drilled to-date, eight resulted in commercial discoveries and one encountered a significant gas accumulation in the south portion of the block. Furthermore, four appraisals were drilled and confirmed about 2Bbbl of OOIP, expected to deliver 700 Mbbl of resources. Two development hubs were delineated so far: the West-Hub and the East-Hub. The West-Hub was sanctioned in Q1 2011. The Mpungi-1 discovery, in the north of the Block, provided additional resources to the development options.

Use of innovative technologies (Fig. 2), largely developed in-house and proprietary, coupled with an aggressive exploration and appraisal campaign continuously focused to reduce time-to-market are the ingredients of the success. From the early stages of the exploration project, the "Integrated Team" approach played a key role (Fig. 3). Interaction among exploration, technical services, reservoir and development teams ensured an effective exchange of information and continuous follow up to provide fast data integration and project updating.

Contrasting Depositional Styles on a Slope System and Their Control by Salt Tectonics: Through-Going Channels, Ponded Fans, and Mass Transport Complexes

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Abstract

The infill history of a salt withdrawal minibasin in the contractional domain of the gravity-driven salt system on the Angolan passive margin has been reconstructed using a high resolution three-dimensional seismic data-set. Well-constrained biostratigraphy has allowed calculation of the growth rate of the basin-bounding structures. Within the interval of stratigraphy investigated, the depositional style of sediments preserved in the basin has changed in response to changes in the rate of growth of the coeval, adjacent salt structures.

During the early part of the basin history, sedimentation in the slope system was dominated by a series of erosional channel complex systems, which are 1-3 km wide and contain a preserved infill 100-200 m thick. The creation of sea floor topography by contemporaneous salt movement and the development of salt-cored anticlines caused the channels to be deflected, diverted, off-set, or deeply incised as they interacted with the developing slope topography.

Subsequent salt movement, and a concomitant increase in the growth rate of the basin-bounding anticlines, led to more elevated topography and the development of extensive slumping of sediment into the basin centers, forming large mass transport deposits. As salt movement continued, the basin became largely enclosed; bound by a well-developed salt wall to the west and a series of complex salt structures to the east, where salt-cored anticlines developed laterally into salt diapirs. These complex structures controlled the flow pathways of sediment both into and out of the basin. The growth rate of the structures constraining the western margin of the basin slowed at this time, and as a result, sediment transported from the east by feeder channels formed ponded fan systems comprised of sheets of sand each formed by multiple small channels.

Understanding the impact that active growth structures can have on sediment distribution and facies development is invaluable in the exploration and production of oil and gas. In this area, the association of the channels with the structure has formed reservoir-trap combinations for four major oil fields, Plutao, Saturno, Marte and Venus, being combined together as the PSVM development. In each field, the specific interaction of the channels with the growing topography has controlled the channel architecture and facies development; this has meant that different development plans, risks and uncertainties are required for each field.

Evolution of the Reservoir Interpretation and Impact of Interpretation Uncertainties in a Channelized Turbidite Field, Block 31, Angola

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Abstract

Block 31, Offshore Angola, lies within the lower slope province of the Lower Congo Basin. The Palas accumulation is situated in the southeast of Block 31 where allocthonous salt bodies bound a series of mini-basins, and movement of the salt has generated tight folds. The main reservoir interval in the area comprises high-quality Oligo-Miocene channelized turbidite sands, transported from the shelf in the east, down-slope to the deep basin floor in the west. Some turbidite channels may have been deflected around salt topography present at the time of deposition. A general geological model to describe the large channelized reservoirs typical of Block 31 has been developed, which summarizes the typical facies, channel geometries, and stacking patterns present (Mayall and O'Byrne 2001; Mayall, Jones, and Casey 2006). For Palas, multiple cycles of seismic data reprocessing and then colored inversion has produced a high-quality dataset from which lithology and fluid prediction is possible. Using both reflectivity and colored inverted seismic data, coupled with sedimentological insights from core and logs, it is possible to identify and map many of the features shown in the Block 31 geological model. The mapped channel systems, associated seismic facies, and major faults are then explicitly built into the Palas geocellular reservoir model. Smaller scale reservoir heterogeneities are represented using transmissibility modifiers associated with the stochastically populated reservoir fill. The impact of uncertainties in the reservoir description – at seismic and sub-seismic scale – on field fluid profile has been assessed. Alternate models have been built and simulated which capture these uncertainties. Currently, a high-resolution dataset covering Palas is being processed. It is expected that this data volume will help resolve some of the uncertainties in the reservoir description before the start of development drilling.

Offshore Southern Oman: New Insights into the Petroleum Potential of the Northeastern Margin of the Gulf of Aden

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Abstract

An undrilled and structurally inverted half graben basin has been identified on the North Eastern margin of the Gulf of Aden in Block 52, Offshore Southern Oman. This block (Fig. 1) was awarded to Circle Oil in September 2005 and originally covered an area of 90,760 sq km. The known stratigraphy of the area ranges in age from Precambrian to Tertiary, based on onshore outcrops, offshore well penetrations, and seismic interpretation. Much of the Paleozoic is absent in the offshore wells. The identified principal reservoir intervals are Paleogene, Hadhramaut, and Upper Cretaceous Aruma Group carbonates (Fig. 2). Potential source rocks include the basal Hadhramaut Group shales, intra-Aruma Group shales, organic-rich units in the basinal Jurassic Sahtan Group, and the Infracambrian middle to upper Huqf Super Group. Sealing units for potential traps are provided by extensive shale and evaporate units of the Miocene Fars, intra-Hadhramaut, and intra-Aruma groups.

Three near-shore wells have were drilled on the block (Fig. 3); all had either oil or gas shows, and there was evidence of a working petroleum system from active offshore seeps. SQB-1, drilled by Amoco in 1979, encountered minor oil and gas shows in Cretaceous Natih carbonates and reached TD of 3314 m in Precambrian igneous basement. KM-1, drilled in 1982 by Amoco, encountered minor gas shows in Infracambrian clastics, though no significant Mesozoic reservoirs were penetrated and the well reached TD at 2178 m in the Precambrian. Well SQBS-1 was drilled by PDO in 1991 and encountered minor gas shows in the Paleogene Hadhramaut carbonates; the well reached TD at 1950 m in crystalline basement. These three wells were drilled on basement highs (Fig. 4) and do not reveal the full story of the basin potential (Fig. 5). In addition, eight shallow Ocean Drilling Program (ODP, 1987) wells were drilled on the outer shelf of Sawqirah Bay to test the shallow stratigraphy as part of global academic research.

The undrilled half-graben basin is about 100 km long by 30 km wide, located 110 km offshore from Sawqirah Bay, and is oriented northeast-southwest, sub-parallel to the coast. Although over 10,500 line km of legacy 2D seismic existed and a further 6,200 line km were acquired by Circle Oil in 2006, only a few regional 2D seismic lines had been shot with extensions into this area, showing few indications of the inversion structures. Circle Oil acquired a detailed survey of 2640 line km in 2011 over this area to understand better the potential prospectivity seen on the older 2D coverage. The 2D seismic surveys had been used to delineate the extent and evolution of this basin, which formed in the Late Cretaceous as an early phase of opening of the Gulf of Aden. Deposition continued in this extensional phase through the Paleogene, with up to 3 seconds TWT of sedimentary fill observed in the deep northwest margin of the half graben; the fill thins seawards to the southeast. A significant compressional phase in the Oligo-Miocene resulted in basinal inversion and the creation of a northeast/southwest-trending structural ridge. A chain of *en echelon* culminations form prospective exploration targets of individual anticlinal closures of up to 43 sq km. Water depths over this prospective area range from 724-956 m and target depths for Paleogene–Late Cretaceous reservoirs are 1490-2850 m.

Evolution of a Pliocene Upper Slope Channel Complex Set, Giza Field, West Nile Delta, Egypt: Interaction of Sedimentation and Tectonics

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Abstract

Across the west Nile Delta, channel complex, channelized lobe, and channel-levee turbidite reservoir systems were deposited throughout the Pliocene following the Messinian salinity crisis and the reestablishment of a muddy depositional slope on the Nile Delta cone. Commercial gas discoveries driven by seismic amplitude anomalies in all of these different turbidite reservoir architectures (Ruby, Fayoum, and Giza fields) are dispersed around the modern day Rosetta Canyon, in water depths ranging from 300m to 900m.

Structurally, the west Nile Delta (WND) is characterized by steep, fault-bounded margins which exerted a fundamental control on the stratigraphic position and fill of slope canyon and channel systems in the Pliocene play fairway. Syndepositional slope collapse has had a significant impact on the development of these slope reservoir systems. The Giza Field gas accumulation is an upper-slope channel complex set characterized by a 160m erosional confinement within a 2.5km wide fairway draping a 20 X 10 km wide plunging anticline, setting up a combination structural-stratigraphic trap. Down slope, the Giza channel complex set can be tracked for a distance of >100 km into a constructional levee confined system on the lower slope.

Visualization of the internal geometry of the Giza channel complex set is based on 3D multiazimuth (MAZ) seismic data tied to extensive conventional core data recovered from both the exploration discovery well and a subsequent appraisal well. The high resolution seismic, combined with log- and corescale observations, provide spectacular insights into the gross seismic architecture, internal geometry, and stacking patterns of the Giza channel complex set.

This paper will demonstrate the facies change and channel geometry variation with the Giza channel reservoir fairway, from incision and bypass, to the initial backfill within a low sinuosity aggradational stacked channel phase, to a more sinuous constructional channel levee fill style having ‘levee lobes,’ to ultimate channel abandonment. Fundamental controls on sedimentation patterns are controlled by a combination of a basin-bounding tectonic control on sediment input points, mass transport processes on the slope generated (generation of accommodation space for precursor lobes), and a deep seated intrabasinal tectonic control that has episodically generated subtle, emergent topography, which has, in part, controlled channel element sinuosity and net to gross.

Review of Petroleum Systems and Hydrocarbon Plays of the Levant Margin, Offshore Israel

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Abstract

Recent drilling activity in the Levant Margin offshore Israel has resulted in the discovery of up to 25 TCF of gas. As exploration efforts continue, the previously under-explored Levant Margin is revealed as one of the most prolific petroleum provinces of the Mediterranean region. Study of regional seismic data show that this margin evolved in three main tectonic phases: Permian to Early Jurassic riffing, middle Jurassic to middle Cretaceous passive margin and late Cretaceous to Tertiary inversion and partial subsidence.

Well results indicate the existence of both biogenic and thermogenic petroleum systems. Dry-gas found in Mari-B, Tamar, Leviathan, and several smaller fields suggests basin-wide charge of reservoirs containing bacterial gas, likely originated in Late Tertiary, organic-rich deep-marine shale. Two play types are associated with the biogenic gas system: (A) the Tamar play includes lower Miocene, deep-water turbidite sands in upper Miocene compressional structures; and (B) the Yafo play includes lower Pliocene turbidites in basin-floor fans and mobilized sand mounds.

The existence of thermogenic petroleum systems in the Levant Margin is indicated by significant, high-grade oil shows found in several wells, although commercial production of these oils has not yet been established. Potential source rocks are organic-rich carbonates of mid-Triassic, mid-Jurassic, late Cretaceous, and early Tertiary age. Two types of plays are considered: (A) Jurassic, fractured shallow-marine carbonates in compressional structures located near the basin margin; and (B) Cretaceous, deep-water turbidite sands found in the deep, central part of the basin. Both play types are planned to be soon tested by drilling.

A Late Jurassic Play Fairway Beyond the Jeanne d'Arc Basin: New Insights for a Petroleum System in the Northern Flemish Pass Basin

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Abstract

The Grand Banks of Newfoundland is a broad continental shelf that extends 450 km into the North Atlantic Ocean. A sequence of Mesozoic rift-events and subsequent break-ups associated with the North Atlantic rift are recorded in a series of complex basins. From the onset of exploration in the 1960's, regional exploration on the Grand Banks has been primarily focused on the Early Cretaceous Ben Nevis and Hibernia formations shallow marine sandstone reservoirs. This early phase of exploration resulted in the discovery of the Hibernia, White Rose, and Hebron fields in the southern Jeanne d'Arc Basin. Collectively, these fields contain approximately 2.5 billion barrels of oil resources. The Terra Nova Field in the southern Jeanne d'Arc basin is the exception to this Early Cretaceous play trend, producing from Late Jurassic braided fluvial reservoirs (Jeanne d'Arc Formation) and contains approximately 500 million barrels of oil resources. This presentation is focused on recognizing and delineating a now proven petroleum system in the North Flemish Pass basin.

Thermal History Analysis of the Beaufort-Mackenzie Basin, Arctic Canada

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Abstract

An integrated thermal history study of the Beaufort-Mackenzie basin of northern Canada is underway using multiparameter data gathered as part of a twelve year petroleum systems research project. New and legacy percent vitrinite reflectance (%Ro) data for approximately 81 wells have been compiled and standardized in order to make maps and cross sections showing thermal maturity trends and to provide paleotemperature constraints for thermal models. Data were quality-assessed by comparing measured %Ro values with other temperature-sensitive indicators (Rock-Eval pyrograms, liptinite fluorescence, and degree of apatite fission track (AFT) thermal annealing) and inconsistent legacy %Ro data were reinterpreted in conjunction with new sample analyses. Extensive organic matter recycling is the major issue affecting data quality and interpretation whereas other factors such as sample caving and oil staining (%Ro suppression) are important but less significant. Multikinetic AFT thermochronology data were obtained for 60 (mainly core) samples from 25 key wells with standardized %Ro data to provide constraints on the timing and rates of burial and exhumation across the study area. Also, thermal maturity and shale compaction trends were used to estimate net erosion magnitudes related to multiple phases of Tertiary deformation and exhumation.

Measured %Ro is highest in exhumed strata along the southern basin margin and lowest in thick Cenozoic strata offshore (north) on the Beaufort shelf. Thermally immature strata persist to depths of > 4 km and to temperatures > 100ºC on the outer Beaufort shelf due to rapid deposition of the thick (> 2.5 km) Plio-Pleistocene Iperk Sequence. Shale compaction trends suggest that 0.5-2 km of postrift Tertiary strata have been eroded from southern and southeastern onshore areas. %Ro-based erosion estimates are more variable and can give much higher values (by a factor of 3 or 4) than the compaction-based estimates, particularly in the Tertiary fold belt of the western and southern areas of the basin. There is a discontinuous increase in maturity across the unconformity that separates Jurassic synrift and Permian prerift strata along the southern basin margin. In the area south of Richards Island, maturity trends suggest that up to 4 km of Permo-Triassic strata may have been eroded prior to the deposition of Jurassic sediments. In the Anderson Plain to the east, erosion has been more extensive and Devonian rocks lie near the surface. Thermal modeling of AFT data from a Devonian sample in the Kugaluk N-02 well (AFT age: 216 Ma) suggests that exhumation was well underway in the Triassic, possibly in association with the onset of rifting. Exhumation may have continued until the Early Cretaceous, followed by reburial under 1-2 km of Cretaceous-Cenozoic sediments that were removed subsequently by erosion. The %Ro data provide important maximum paleotemperature constraints for integrated thermal history models based on multikinetic, AFT thermochronological data collected for the synrift and postrift successions.

Petroleum Systems and Seismic Expression of Exploration Plays, Canadian Arctic Margin, Beaufort Sea

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Abstract

The Canadian Arctic margin, from the Alaska/Canada boundary north-northeastward almost 1,000 km to the north of Banks Island, represents one of the largest sedimentary wedges in the world. With primary input from the Mackenzie River, the margin appears to have all the necessary components of a “world-class” petroleum province: possibilities of structural and stratigraphic traps, multiple potential source rocks, an abundance of potential reservoirs and seals, and timely migration resulting in almost 50 hydrocarbon accumulations discovered to date. However, lack of a large enough discovery to warrant commercial production has resulted in exploration being limited only to the shallow parts of the Mackenzie River Delta (water depths <40 m). Interpretation of recent, long-offset (9 km), deep (18-sec recording), prestack-depth migrated (PSDM to 40 km) data has resulted in extending the petroleum potential to deeper waters and to areas away from the delta. Industry has recognized this potential by acquiring leases beyond the shallow waters, but the full potential of the area will only be realized by new exploratory drilling.

Source to Sink Assessment of Oligocene to Pleistocene Sediment Supply in the Black Sea

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Abstract

Despite having at least one major river, the Danube, supplying sediment to the Black Sea, the presence of significant deepwater clastic reservoirs has always been viewed as the major exploration risk. Source to sink concepts have been used examine this risk. Reconstruction of plausible paleodrainage scenarios combined with knowledge of the paleogeography, climate and hinterland geology have been used to estimate paleosediment budgets and provide an assessment of reservoir quality in the basin. Analysis of the basin fill, interpreted from extensive seismic coverage calibrated by wells, allows further refinement of the rates of sediment supply. A forward model of the basin fill has been created that successfully produces a postulated fill matching the observed geometry of the fill of the basin.

Our analysis shows that fluvial drainage into the Black Sea from the Oligocene through to the Pleistocene has been dominated by small, local, mountainous hinterland drainage, formed in the many surrounding orogens and volcanic arcs. The resulting sediment supplied is predicted to be of low quality. Likely routes for large long-lived fluvial systems draining the continental shields to the north and west, include many updip sediment-trapping basins on the way to the Black Sea, suggests that sediment entered the basin in volume only in the latest Pleistocene. Therefore the risk of finding large volumes of sandstone in the form of large pre-Pleistocene deep-water fan complexes is high. However, smaller volume locally sourced fan-aprons may be common throughout the pre-Pleistocene succession around the margins of the basin.

The “Sink” of the Danube River Basin: The Distal Danube Deep-Sea Fan

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Abstract

The Danube River basin and the Black Sea represent a unique natural laboratory for studying source to sink and global change. We will address information on the "active sink" of the system which represents the area of active deposition: sea level variation, sediment balance, and neo-tectonics. Also, we will discuss the evolution and quantification of climate, tectonics, and eustasy on the sedimentation in the western Black Sea basin, along both southern and northern margins, obtained from understanding the Danube deep-sea fan processes and sedimentation.

In the last decade, many of the geosciences studies carried out in the Black Sea have focused on the Holocene marine transgression. This topic has been fully discussed and is still a matter of debate. Since the DSDP drillings, the lithology and mineralogy of deep sediments from the Black Sea have been well studied. However, only few recent studies have focused on the deep-sea morphology and turbidite sedimentation in the western Black Sea basin, where the main depositional feature is the Danube submarine fan.

Oceanographic surveys in the Black Sea in 1998, 2002, and 2004, carried out in the framework of French-Romanian joint project and the European ASSEMBLAGE (EVK3-CT-2002-00090) project, have collected a large amount of data (Multibeam echo-sounder data, Chirp seismic, Kullenberg and Calypso cores). This discussion is based on new insights from recent coring and seismic data recovered at the boundary of influence of both the distal part of the Danube turbiditic system and the Turkish margin. This data set provides a good record of changes in the sedimentary supply and climatic changes in the surrounding Black Sea during the last 25 ka. Based on this study, we demonstrate that the deep basin deposits bear the record of the late Quaternary paleoenvironmental changes.

Finally, the western Black Sea basin constitutes an asymmetric, subsident basin bordered by a northern passive margin with confined mid-size, mud-rich turbiditic systems, and a southern turbiditic ramp margin, tectonically active.

From Petroleum Systems Modeling to Fluid Prediction—A Story: Choosing the Right Kinetics may be the Wrong Thing to do

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Chevron

Abstract

Choosing the right kerogen for hydrocarbon (oil and gas) generation kinetics to predict hydrocarbon phase and properties such as API gravity and GOR using petroleum systems models is usually a challenge. Common procedure in industry is to select a multi-component kinetics dataset based on available geochemical data and a basin analogue. This kinetics is usually derived from a measurement of 1 or 2 samples of an immature source rock representing a specific kerogen type or source facies. Testing indicates that it currently makes little difference whether a programmed default is used or a basin-specific dataset is utilized. The important question remains, how well does a selected sample represent the source rock variability within the fetch area? This question is quite often neglected. In addition to this conceptual issue, the alteration of hydrocarbons during migration and within the trap are usually not explicitly modeled, largely as a result of the limited understanding of the processes involved, which precludes their quantification. Examples from the South Atlantic continental margins, applying this new solution, which implicitly includes many of the important factors such as source rock variability and migration effects, will be presented. The proposed solution results in significantly improved prediction of the quality of hydrocarbon product, phase, and properties such as GOR, API gravity, and viscosity.

Application of Geomechanics-Based Restoration in Structural Analysis along Passive Margin Settings—Deep-Water Niger Delta Example

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Abstract

The current emphasis in petroleum exploration includes going deeper in mature basins such as Gulf of Mexico, West Africa and elsewhere, or looking for unconventional hydrocarbon accumulations. While the fundamentals of the exploration process (*i.e.*, evaluating risk and resources of target areas) remain constant, the questions that are asked for each of the above continue to change in the order of complexity. The fundamental step of basin modeling work flow involves capturing evolution of the structural geometry (and kinematics) through time starting with the present day subsurface geometry. Recent advancements in fields of geomechanics and structural geology have given rise to geomechanics based structural restoration. An example study in the deep-water Nigeria fold-thrust belt illustrates the strength of the approach in that it utilizes rocks having distinctive mechanical properties to arrive at structural configuration through time in a manner similar to kinematic restorations. Results indicate the usefulness of the approach in validating interpretation, re-constructing structural history, and gather insight into the deformation mechanisms and rock property evolution. The primary advantage of this technique over the more conventional methods is that no kinematic model is imposed as an input. In addition, several quantitative deformation parameters can be output to help understand structural genesis and potential impact on petroleum system. In the future, quantitative estimates of deformation and stress may be used to better answer challenging questions related to trap history, evolution of reservoir and seal, and permeability heterogeneity within reservoirs.

Sequestration of Organic Matter in Marine Mud: Flume Experiments, Biogeochemistry, Mass Physical Properties, and 3D Modeling

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Abstract

Organo-clay fabric and physico-chemistry of marine mud play important roles in early sediment diagenesis including the development of mass physical properties, consolidation behavior, and sequestration of organic matter (OM) in sediments over geologic time. Transmission electron microscopy (TEM) images of nano- and microfabric reveal that organic matter is sequestered following enzymatic digestion despite the pervasive openness of pore-fluid pathways observed in 3D rotated images. The locations of sequestered organic matter correspond to those predicted by modeling of the potential energy of interaction. Initial flume experiments on high porosity clay-mineral-rich mud deposited under dynamic flow and static (vertical settlement) conditions demonstrate differences in clay fabric and the distribution of organic matter (we define the term organo-clay fabric as the contiguous association and arrangement of organic matter and clay domains). These differences in organo-clay fabric impact the preservation-degradation mechanisms and dynamics during depositional and burial processes. Organo-clay fabric and physico-chemical modeling of potential energy fields coupled with direct observations of organo-clay fabric, three-dimensional (3-D) clay fabric reconstructions, sediment static and dynamic properties, and controlled flume experiments are providing new insight into the developmental history of sedimentary sequences, nano- to macroscale environmental processes, and diagenesis from unconsolidated mud to shale.

Structure and Prospectivity of the Ceduna Delta—Deep-Water Fold-Thrust Belt Systems, Bight Basin, Australia

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Abstract

The Ceduna subbasin forms part of the under-explored but highly prospective frontier Bight Basin located on the southern margin of South Australia. Structural mapping of the Ceduna subbasin reveals two separate delta lobes/systems deposited in the late Albian-Santonian and late Santonian-Maastrichtian. Each system is comprised of an updip delta top linked via a shale detachment to a down-dip delta toe or deep-water fold-thrust belt. These delta lobes are separated by a transgressive sequence of Turonian-Santonian age that deposited a thick marine mud, up to 2000 m in places. Like the Niger Delta, this marine mud forms the detachment for the overlying Santonian-Maastrichtian delta—deep-water fold-thrust belt system and is also a proposed source rock. An Albian marine mud forms the detachment for the older Cenomanian system and is also thought to exhibit source rock potential.

We examine the differences in structural style between the western and eastern parts of the basin, the west being dominated by the Cenomanian lobe and the east by the Santonian-Maastrichtian lobe. Recent work on the sedimentary provenance of the basin suggests two different mechanisms were responsible for deposition of the delta lobes in the west and east, as well as significant changes in regional tectonics dominating the basin fill history. This has resulted in the deposition of two delta—deep-water fold-thrust belt systems rather than a continuous system as is commonly observed elsewhere in Cenozoic analogues such as the Niger Delta. Evidence from the drilling of Gnarlyknots-1A on the delta-top suggests excellent reservoir quality in the Santonian-Maastrichtian system; the potential for seal and source development increases farther offshore toward the deep-water fold-thrust belts. The abundant availability of deep-water contractional targets, combined with modeled increase in source and sealing potential farther offshore, results in a highly prospective system in both the Cenomanian and Santonian-Maastrichtian deep-water fold-thrust belts.

Author Index

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W

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