Atlantic Margin of Ireland – Research and Exploration in an Emerging Petroleum Province

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Abstract

The North Atlantic Mesozoic rift basins are tectonically linked and share a common evolution related to the opening of the North Atlantic Ocean. Ireland and Newfoundland-Labrador are commonly accepted as conjugate margins and both contain substantial yet-to-find petroleum potential.

Ireland has recently experienced a surge in activity with the issuing of 28 Licensing Options in the 2015 Atlantic Margin Licensing Round, which now brings the number of active exploration authorisations to its highest levels since offshore exploration began in the 1970's. Ireland's North Atlantic emerging petroleum province has had only limited exploration with 52 exploration and appraisal wells drilled to date. The highly competitive nature of the Licensing Round was partly due to the significant discoveries made in the conjugate Flemish Pass Basin (Bay du Nord and Harpoon) offshore Newfoundland, which has heightened speculation of similar geology in the Porcupine Basin in Ireland. Another key to the focused industry attention was the availability of new long offset seismic data acquired in regions previously without modern 2D data, further demonstrating the similarities between the margins. This government led acquisition programme has helped to illuminate the prospectivity of underexplored, and untested, portions of the Irish offshore.

Ongoing conjugate margin research includes a major collaborative Transatlantic geochemical source rock study by Nalcor Energy and Ireland's Petroleum Infrastructure Programme (PIP), which provides further insight on the tectonic evolution and hydrocarbon potential of the conjugate margins of Newfoundland-Labrador and Ireland. An additional Irish-focused initiative includes a new, updated stratigraphic framework for all Irish offshore basins. This new framework will assist with our understanding of the regions' evolution, the correlation to neighbouring regions, and similarities with the conjugate margin in Canada.

Influence of paleorelief on structural segmentation of Albian carbonate platforms at the Badejo High, Southern Campos Basin

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Abstract

The shallow water carbonate rocks lying above the Badejo Basement High have over 30 years of successful oil production. Well known in terms of stratigraphic arrangement and permo-porosity, these accumulations are problematic when the subject is its structural control. One relevant point regarding these accumulations is whether or not the paleorelief below these carbonate platform controlled the fragmentation and downslope gravity movements. In detail, the oil fields of Albian age at the Badejo High are above salt pillows and welds, overlying a buried basement step that, in map view, bends from N-S to NE-SW. Gravitational structures in the sedimentary sequences above the salt layer are mostly collinear with the paleorelief architecture of the basement beneath. Such alignment motivated the investigation of a possible passive influence of the substrate after cessation of the fragmentation and basinward gliding processes. Evidences supporting this idea came from an integrated approach that included analysis of well logs, seismic interpretation, section restoration and generation of palinspastic maps. These techniques revealed a clear association of the buried basement step and the salt-related fault patterns. Two distinct post-salt fault arrangements were identified: one of NW-SE subparallel planar normal faults; and another with radial divergent map view, dominated by non-planar N-S to NNW-SSE listric faults, following with the buried bend of the basement high. The tracking of lateral movements through time deduced from the sequential restoration indicates that the apices of deformation occurred in the Eoalbian-Cenomanian and it was likely associated to the ESE tilting of the basin. The progressive deceleration of the basinward gliding, above the Badejo Basement High, started in the Late Cretaceous until its complete cessation in the Paleogene.

Genetic Comparison of Crude Oils from West Africa and South American Conjugate Basins

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Abstract

Continuing research has clarified the tectono-structural history of the Atlantic conjugate margins. This includes the creation and segmentation of source rock depocenters. Petroleum geochemists have concurrently examined the nature and distribution of these associated source rocks by characterizing crude oils within a field, then a basin and across a series of basins. Crude oils possess important biological clues that can be used to unravel their genetic history from source to trap and beyond. Lacustrine source distributions of the South Atlantic were investigated by Brice et al., 1980; then comparisons of oil chemistries from both margins were published by Schiefelbein et al. (1997; 1999; and 2001).

Recognition and characterization of compositionally distinct oil types or families infers paleo-environmental conditions of source rock deposition and possible age. Clearest results are obtained from pure end-member oils from a single lithology, single paleo-environment source but this is uncommon to the South Atlantic margin with its compound basins, usually with drift-age marine fans overlying multi-stage rifts. Depositional environments may grade episodically from lacustrine to marine so that in late rift to sag phases, source rocks composed of mixed kerogens are deposited. Oils from such sources in similar phases of maturity may mimic mixed oils from discrete sources co-mingled in a common reservoir.

Statistical analysis of some 1500 oils allows separation into five major families: Early SynRift; Late SynRift/Sag; Marine/Mixed; Marine; Tertiary Deltaic. Incorporation of additional geologic constraints from tectono-structural mapping suggest that oil family and sub-family distributions often relate to sediment thickness and basin to sub-basin structure; lacustrine oils show strong correlations of age and location between conjugate salt basins; and marine oils demonstrate age correlations related to global ocean anoxic events.

Tectonic, structural and fracture permo-porosity analysis in a Tertiary carbonate platform at the northern portion of the Pará-Maranhão Basin, Brazilian Equatorial Margin

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Abstract

The Para-Maranhão Basin is located in the Brazilian Equatorial Margin and its shallow water portion is characterized in the northern part by an extensive carbonate platform with up to 5 km thickness. This platform was the target of intense oil exploration in the late 70's and beginning of the 80's, when a light oil discovery was made in fractured carbonate reservoirs of Eocene age drilled by the well 1-PAS-11.

Although the analyzed area is bounded by two distinct branches of the Saint Paul Fracture Zone, this research showed no evidence of transcurrence in the Cenozoic, but a gravitational control characterized by a NE-SW extensional system. This extensional system resulted in the formation of NW-SE trending listric faults during the Eocene with detachment surface in the Upper Cretaceous.

Consequently, several structures developed during the Cenozoic evolution of the area, such as roll-over folds, folds linked to displacement gradients along the faults, relay ramps and breached relay ramps, and inversion structures. These structures were formed at different times and at different places around the basin and were associated with their own local or basin-wide stress fields. These stress fields can be used to predict the type and fracture orientation patterns likely to occur in the structures.

Based on this information, it was possible to identify areas of more intense fracturing and its relationship to permo-porosity data of the reservoir, quantified by the analysis of density profiles, measurements made on cores, and other methodologies. Therefore, this study has significant implications for the hydrocarbon exploration in the northern part of Pará-Maranhão Basin.

Crato Formation laminites - a representative geomechanical pre-salt analogue?

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Abstract

Aptian-Albian lacustrine laminites from the Crato Formation (CF), Araripe Basin, Brazil, are well known for their fossil record and recognised as a Fossil Lagerstätte. However, with recent hydrocarbon discoveries in the pre-salt layer of the Brazilian marginal basin, CF has been considered as an analogue for carbonate reservoirs. Easy access to the outcrops and its range of facies (laminar, convolute, concretions) and structural heterogeneities (open-mode fractures, faults) makes it worth investigating. How representative are the CF laminites as an analogue for Barra Velha Formation, Aptian lacustrine carbonate reservoir, Santos Basin, offshore Brazil.

In this study, different CF laminites were analysed and characterised using petrophysical and visual techniques, such as porosity, microscopy, X-ray tomography and photographs. After initial analysis 20 samples were deformed triaxially using a range of confining pressures (20MPa - 50MPa). Once peak stress was reached the tests were stopped and the samples removed for analysis of the deformation response. Based on comparison of per- and post-deformation properties, as well as image analysis indicate a strong link between laminite facies characteristics and deformation response. Even though different deformation responses were observed the overall increase in porosity due to fracturing for non-faulted laminites was 5.94% (±1.66). Laminites sampled from a small fault zone showed an increase in porosity of 17.11% (±4.48) due to triaxial deformation. This indicates that deformation behaviour for laminar laminites could be predicted based on key properties such as porosity, permeability and mineralogy. However, for faulted samples these properties alone cannot predict deformation behaviour.

Initial petrophysical results suggest that CF laminites can be considered a representative analogue of naturally fractured reservoirs. However, further analysis considering the geomechanical behaviour is still outstanding.