Deep-Water Core Workshop, Northern Gulf of Mexico

Abstracts

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Core Characterization of Slope-Channel and Channel-Levee Reservoirs in Ram Powell Field, Gulf of Mexico

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Abstract

Cores taken from the Ram Powell Field, offshore Alabama, have provided the opportunity for detailed reservoir characterization of slope-channel and channel-levee reservoirs. The two reservoirs examined are the L Sand channel-levee reservoir and the N Sand channel sand reservoir.

The L Sand is characterized as a fining-upward unit of laminated to thin-bedded sand, silt, and shale. The dominant grain size of the reservoir is silt with permeabilities ranging from 10 to 1000 md and the dominant turbidite facies assemblage is T_{CDE}. The L Sand reservoir is extremely well connected based on production performance. Connectivity is further enhanced by breakdown of internal reservoir barriers during production. The reservoir connectivity appears to be over 4000 acres based on material balance estimates.

The N Sand is characterized as a high energy amalgamated channel-fill sand deposited in a confined pre-existing scour. The sands exhibit high reservoir quality with porosity averaging 28% and permeabilities ranging up to 1400 md. The sands exhibit high net-to-gross ratios and sand on shale amalgamation surfaces are limited in number. Based on production performance, pressure, and well log interpretation the N Sand is well connected over a large area in a pressure sense but the paths of connection are tortuous and the reservoir contains many internal barriers and baffles.

The L Sand and N Sand cores provide a good contrast between a high-energy channeled reservoir and a low to moderate energy channel-levee reservoir. While rock properties are not significantly different between the two reservoirs, reservoir performance is significantly better in the reservoir with the poorer properties due to better connectivity within the reservoir.

Core, Log, and Seismic Characteristics of a High-Performance Turbidite Reservoir in a Salt-Withdrawal Minibasin: The Upper Miocene Yellow Sand, Mars Field, Gulf of Mexico

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Abstract

The discovery and development of the Mars field contributed to the excitement about deep-water hydrocarbon potential that was taking place worldwide in the 1990's. The Mars field has become an important example of the economic viability of this new petroleum frontier. The success of the Mars development is associated with high rate/high ultimate wells delivering as expected. In the past 5-1/2 years the field has produced 241 MMBO and 257 BCF of gas from 21 wells.

Whole core acquired during the appraisal phase of the Mars field was an important data set, which furthered confidence in the justification of the development project. Of the more than 1,000 ft of core taken at Mars, roughly half is from four appraisal wells that were cored in the Yellow interval. The Yellow sands are Late Miocene in age (~ 8.0 my) and the reservoir architecture is a combination of turbidite sheet-sands and channel-fill complexes.

Data collected from the Yellow core have strongly influenced our interpretation of reservoir architecture, reservoir volumetrics, and well deliverability (expected production rates and expected cumulative recovery). The reservoir architecture, reservoir volumetrics, and related reservoir parameters continue to be integrated into dynamic reservoir simulations. The ongoing simulation effort provides a basis for the surveillance and long-term management of the Yellow reservoir.

Core Description of Miocene Deep-Water Turbidite Reservoirs, Pompano Field, Mississippi Canyon Area Blocks 28/72, Offshore Louisiana

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Introduction

Pompano Field produces from Pliocene and upper Miocene reservoirs at the modern shelf-slope break 24 miles south of the Mississippi River delta. The Pompano platform is a 40-slot conventional fixed-leg structure located in Viosca Knoll Block 989 in 1290 feet of water. Nine of the fourteen Miocene wells are producing from a template in 1865 feet of water and are tied-back 4.5 miles to the Pompano platform. Since 1994, the field has produced 20.4 mmbo and 20.9 bcf from the Pliocene and 49.9 mmbo, and 63.6 bcf from the Miocene. This presentation focuses on the upper Miocene reservoir, herein referred to simply as “the Miocene.”

Arco discovered the Miocene reservoir at the Pompano field in 1981. Two appraisal wells cored the Miocene section in 1989 and 1990. It is a relatively shallow (-10,000 feet tvdss) oil reservoir with a seismic direct hydrocarbon indicator (DHI), typical of the Gulf of Mexico shelf edge plays. The reservoir is a combination structural and stratigraphic trap with deep-water turbidite sands draped across a structural nose. The Miocene section of the field is not faulted and production anomalies are controlled by the stratigraphic architecture (Harrison *et al.,* 2001).

The upper Miocene reservoir is a deep-water turbidite system that scoured and filled an upper/middle slope, low-relief canyon with an aggradational channel/overbank system. The channels are highly amalgamated resulting in stacked reservoirs with vertical and lateral communication (Pulham *et al.* 1991). Localized overbank deposits within the channel complex are also in pressure communication.

Whole Core of a Late Miocene Pay Zone in Crosby Field, Mississippi Canyon 898-899, Gulf of Mexico

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Introduction

In addition to the giant producing fields of Mars and Ursa, substantial hydrocarbon resources have been discovered in the Mars basin. The Crosby field is one example. Seismic and well log correlations from Ursa to Crosby are excellent, allowing incorporation of the reservoir horizons into the basin-wide interpretation. Reservoir properties at Crosby were expected to be similar to equivalent intervals cored at Mars and Ursa. Pre-drill plans called for obtaining whole core only if a pre-determined set of criteria were met.

The Crosby field is located in the Mars basin, Central Gulf of Mexico, seventy miles south of the Mississippi Delta, in 4392' of water. Shell and BP are working interest owners of this 1997 discovery, which is situated at the southeastern rim of the Mars basin, 9 miles SE of the Ursa TLP location. Initial drilling found three main reservoirs associated with 3D seismic amplitude anomalies. However, the lowermost reservoir, the Lower Green Bice sand, showed poor wireline log reservoir characteristics in the MC 899 #5 well (#5) compared to the 9900' northward offset MC 899 #4 well (#4), a wet penetration drilled in 1991. The downdip confirmation well, the MC 899 #5ST1 (#5ST1), cored the Lower Green Bice sand to understand the differences in log character between the two wells.

Core, Log, and Seismic Characteristics of a High Rate Amalgamated Channel Reservoir in a Salt-Withdrawal Minibasin: The Upper Miocene "Above Magenta" Sand, Ursa Field, Northern Gulf of Mexico

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Abstract

The upper Miocene "Above Magenta" sand at the Ursa Field, one of the highest rate producing reservoirs in the northern deep-water Gulf of Mexico, has been extensively studied to understand its excellent performance characteristics. Several models have been proposed to explain its depositional framework. Stancliffe *et al.* (1999) interpreted the "Above Magenta" interval as a leveed channel system, whereas Schofeld and Serbeck (2000) interpreted the same interval as a shingled sheet sand, comparable to "HARP" systems observed on the modern Amazon deep sea fan. More recent interpretation, utilizing recently acquired log, seismic, and production data, as well as existing core and log data, has provided the basis for an alternate depositional model, in which the "Above Magenta" reservoir is considered to be an amalgamated channel system.

The "Above Magenta" reservoir is visualized on seismic data as a discontinuous event with evidence of shingling. Internally, the reservoir can be divided into a sand-rich lower unit, and a sand-poor upper unit. Sand packages in the lower unit display blocky gamma-ray and resistivity patterns on well logs, but the packages are not easily correlatable except over very short distances. Core samples from the lower unit are massive to graded, with evidence of internal scouring and erosion. These data suggest that the lower unit of the "Above Magenta" reservoir is made up of amalgamated sandy channels.

The upper unit of the "Above Magenta" reservoir has a serrate bell-shaped log pattern with high gamma-ray and low resistivity values. Core samples show that this unit consists of thin-bedded heterolithic sediments, characteristic of channel abandonment or levee/overbank deposits. Both units have sufficiently high net-to-gross, and are sufficiently amalgamated to provide good internal reservoir continuity and hydraulic connectivity.

Characterization of Fine-Grained Deep-Water Turbidite Reservoirs: Examples from Diana Sub-Basin, Western Gulf of Mexico

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Introduction

The Diana sub-basin is situated in the western Gulf of Mexico 160 miles south of Galveston in approximately 4800 ft of water. The main reservoirs in the Diana sub-basin are late Pliocene in age and are composed primarily of turbiditic sandstones and shales that were deposited as lowstand fans within an intraslope basin setting. The sub-basin is relatively large, consisting of 2 narrow feeder-corridors to the north, which open into a large, low-relief basin approximately 20 miles wide by 20 miles long. It is about 3–4 times the size of the next largest up-dip intraslope basin. Detailed analyses of well-log and core data from the Hoover, Diana and South Diana fields within the sub-basin suggest that the main reservoirs for each of these fields were deposited in distinctly different depositional settings. These reservoirs are interpreted to reflect the change from a confined feeder channel system at the Hoover Field to a weakly confined/distributary channel complex at Diana Field to distributary lobe/sheet complex at South Diana Field.

To date, five discoveries have been made in the sub-basin, including the Hoover, Diana and South Diana fields. ExxonMobil is the operator for all three of these fields with 66% working interest whereas BP holds a 33% interest except for one of the South Diana blocks, Alaminos Canyon Block 66, which is 100% ExxonMobil. The primary reservoir interval at the Hoover Field is the upper Pliocene P1:10 sand and the field is a low-relief, four-way closure situated on Alaminos Canyon Blocks 25 and 26. The reservoir at the Diana Field is the upper Pliocene A-50 sand, which is slightly younger than the reservoir at Hoover Field. The field is located on East Breaks Blocks 945, 946, 988 and 989 on the east flank of a north-south trending salt-cored ridge. Hydrocarbons are trapped by a combination of structural closure and stratigraphic onlap. The reservoir at the South Diana Field is the distal equivalent of the A-50 sand at Diana Field and is located on Alaminos Canyon Blocks 21, 22, 65 and 66. The primary trap is an up-dip stratigraphic onlap onto a salt diapir in combination with small downdip faults. The main development facility for the sub-basin is located at the Hoover Field, and Diana Field is a subsea tie back to Hoover. First production for both Hoover and Diana fields was in 2000.