

## Improving Performance Prediction in Deep-Water Reservoirs: Learning from Outcrop Analogues, Conceptual Models and Flow Simulation

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### Abstract

Seismically conditioned, geostatistical models of deep-water reservoirs typically predict overly uniform sweep and correspondingly late arrival of water and/or gas, compared to the performance of the reservoir verified from well history and 4D seismic data, where available. Under-representation of the spatial organization and permeability of key stratigraphic heterogeneities are considered to be the likely cause of this predictive failure. To examine the effects of stratigraphic heterogeneities on fluid flow, fine-scale, 3D geologic models, based on conceptual models and descriptions of deep-water channel deposits in Southern California, were constructed. The stratigraphic heterogeneities include high permeability gravel-rich, sandy turbidites in the axis of channel-fills and low permeability thin-bedded, muddy turbidites at the margins of channel-fills. Inclusion of these heterogeneities in the models had a significant negative impact on recovery efficiency and timing of injected fluid breakthrough. The results from these simple simulation experiments compared favorably with behavior observed in subsurface deep-water reservoirs. A remaining challenge is to preserve the effect of these stratigraphic details in coarser-scale simulation models, and two such methods are discussed.

### Introduction

Accurate predictions of flow rates, timing of water and gas breakthrough, and hydrocarbon recovery are essential to determine the economic viability of deep-water reservoir developments. Typically, this is achieved by constructing a stochastic (geostatistical) geologic model, based on an interpretation of well logs and seismic data, up-scaling, and carrying out fluid flow simulations to predict reservoir performance. This process has been routinely applied to a number of deep-water fields offshore West Africa that have

recently come onstream. However, we have found that these types of models have predicted overly uniform sweep of the reservoir with correspondingly late arrival of water and/or gas, compared to the performance of the reservoir verified from well history and 4D seismic data, where available.

Fig. 1a shows, schematically, a prediction of the sweep of a deep-water reservoir under a simple water injection production strategy. The model predicts even, homogenous sweep of the reservoir and delayed breakthrough at the producer. In contrast, Fig. 1b shows a typical distribution of water in the reservoir that might be resolved from 4D seismic data. More heterogeneous movement of water is observed, with areas of unswept oil and rapid movement of water towards the producer. The predicted water rate at the producer shows much later breakthrough and a lower rate than what is actually observed (Fig. 1c). The patterns of water sweep observed on the 4D data very clearly show that fine-scale stratigraphic features (e.g., channel fills) exert a strong control on the movement of water through the reservoir.

The purpose of this paper is to demonstrate that organized stratigraphic architectural elements can explain the subsurface observations seen in deep-water reservoirs by building fine-scale 3D geologic models based on outcrop descriptions and property measurements of deep-water channel deposits. The outcrops used in this paper come from the Capistrano Formation, San Clemente, California.

### Geologic Description of the Capistrano Formation and Construction of the Geologic Model

The Capistrano Formation, exposed at San Clemente, California, records the deposition of Late Miocene to Pliocene rocks in a deep-water environment. The Capistrano Formation is an excellent analogue for the producing deep-water reservoirs offshore West Africa that were deposited in a confined setting on the continental slope.

The rocks of the Capistrano Formation exhibit erosional surfaces interpreted as channel cuts (e.g., Walker, 1975; Campion et al., 2000; 2005). The fill within the channels includes typical deep-water lithofacies such as gravel-rich turbidites, sandy turbidites, and thin-bedded muddy turbidites. The channel fills are laterally stacked forming an amalgamated, confined channel complex. In 3D, we would expect the channel complex to have a sinuous shape, similar to the geometries observed on many seismic surveys.

Deep-water rocks can be interpreted in terms of a stratal hierarchy (Fig. 2; Campion et al., 2005; Sprague et al., 2002; 2005). The outcrops of the Capistrano Fm. include all levels