T-15 AVA Stochastic Inversion of Pre-Stack Seismic Data and Well Logs for 3D Reservoir Modeling

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Abstract

This paper describes the application of a novel AVA stochastic inversion algorithm to quantitatively integrate pre-stack seismic data and well logs. The stochastic inversion algorithm is used to characterize flow units of a deep-water Miocene reservoir located in the central Gulf of Mexico. A detailed fluid/lithology sensitivity analysis is conducted to assess the nature of AVA effects in the study area. Conventional analysis indicates that the shale/sand interface represented by the top of the hydrocarbon-bearing turbidite deposits generate typical Class III AVA responses. On the other hand, layer-dependent Biot-Gassmann analysis shows significant sensitivity of the P-wave velocity and density to fluid substitution. Accordingly, AVA stochastic inversion, which combines the advantages of AVA analysis with those of geostatistical inversion, provides quantitative information about the lateral continuity of the turbidite reservoirs based on the interpretation of inverted acoustic properties (P-velocity, S-velocity, and density), and lithotype (sand-shale) distributions. The quantitative use of rock/fluid information through AVA seismic data, coupled with the implementation of co-simulation via lithotype-dependent multidimensional joint probability distributions of acoustic/petrophysical properties, provides accurate 3D models of petrophysical properties such as porosity, permeability, and water saturation. Moreover, by incorporating lithology into the inversion and fully integrating pre-stack seismic and well log data, the vertical resolution of stochastically inverted 3D reservoir models is considerably higher than that of deterministically inverted reservoir models, thereby significantly reducing development risk.

Introduction

Anadarko's Marco Polo deepwater development project is located in Green Canyon Block 608 in the Gulf of Mexico, approximately 175 miles south of New Orleans, in a 4300' water depth environment. Hydrocarbon production originates from reservoirs consisting of Tertiary deepwater sand deposits. This paper considers a small portion of the Marco Polo Field where hydrocarbon-bearing sand units pertain to the "M" series and are buried at depths between 11500 and 12500 ft. The overall "M" series consists of sandy turbidite reservoir deposits interbedded and separated by muddy debris flows. These reservoir intervals are interpreted as stacked, progradational lobes within an overall fan complex. The massive and planar stratified sands exhibit excellent interparticle porosity. Rock-core measurements indicate excellent intrinsic properties: 30%+ porosity, and 100-4000 millidarcies of nominal permeability. We used 3D pre-stack time migrated seismic amplitude data to quantify the vertical and lateral extent of the main turbidite reservoirs. AVA fluid/lithology sensitivity was conducted as a preamble of AVA simultaneous stochastic inversion to simulate elastic and petrophysical properties in the inter-well region of the reservoir.

AVA Fluid/Lithology Sensitivity Analysis

A detailed fluid/lithology sensitivity analysis was conducted to assess the nature of AVA effects in the study area. Wellbore and pre-stack seismic data were analyzed to determine the sensitivity of elastic properties to changes of lithology, porosity, fluid content, saturation, and shale content. A sensitivity analysis was also performed to quantify the AVA response of layer interfaces associated with the main reservoir intervals (M-10, M-40, and M-50). Such sensitivity study consisted of (1) analysis of fluid/lithology sensitive logs, (2) crossplot analysis, (3) Biot-Gassmann fluid substitution, (4) AVA reflectivity modeling, (5) numerical simulation of synthetic gathers, and (6) partial angle stacking.

The analysis of fluid/lithology sensitive logs combined with cross-plot analysis and Biot-Gassmann fluid substitution indicated significant sensitivity of P-wave velocity to changes of pore fluid (Figure 1).

Additionally, AVA analysis (which includes angle-dependent reflectivity modeling), comparison of synthetic and real angle gathers, and amplitude analysis from partial angle stacks, corroborated the presence of AVA effects on the study area. The sane analysis indicated that the shale/sand interface at the top of the hydrocarbon-bearing turbidite deposits was associated with typical Class III AVA responses (Figure 2).

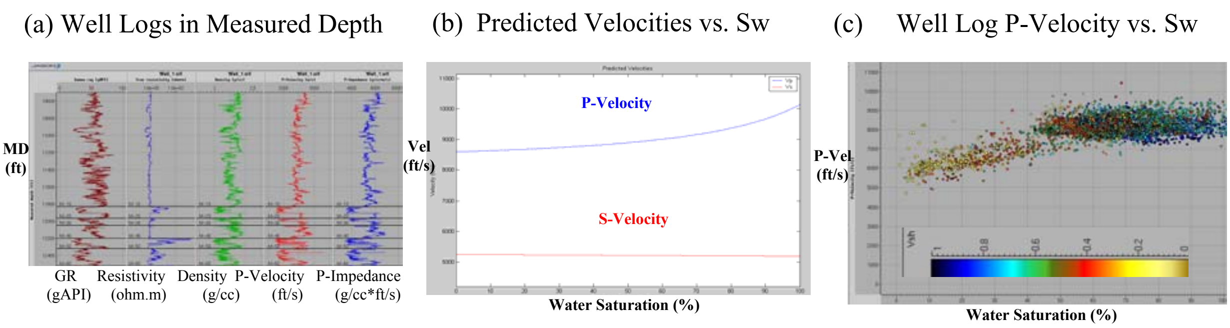

Figure 1. (a) Fluid/lithology sensitivity well logs showing the characteristic low values of P-velocity, density, and acoustic impedance for hydrocarbon-bearing sands; (b) Cross-plot of predicted P- and S-velocities vs. water saturation using Biot-Gassmann equations: P-velocity clearly decreases when hydrocarbon saturation increases. This behavior is also indicated by well log data (Panel c).

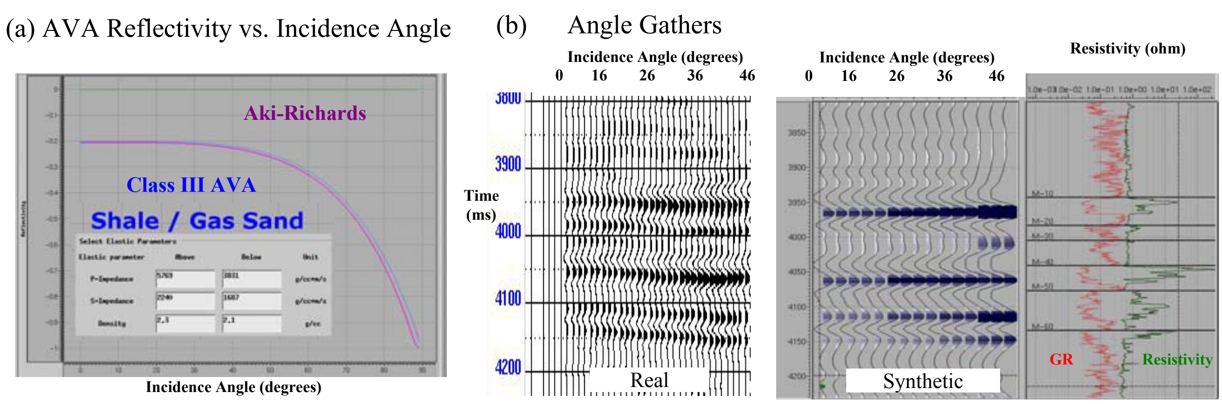

Figure 2. AVA sensitivity analysis results: (a) AVA reflectivity at the shale/gas-sand (M-10) interface, showing a Class III AVA response; (b) comparison between real angle gathers (left) and synthetic angle gathers (right) generated from well-log data indicate an increase in amplitude with an increase of the angle of incidence.

AVA Simultaneous Stochastic Inversion

Four 3D partial angle stacks were simultaneously inverted with well logs using a novel stochastic inversion technique. This new inversion algorithm is based on the Markov Chain Monte Carlo (MCMC) method [1] and combines the Gauss random field conceptual model underlying traditional geostatistics with iterative local updates inherent to nonlinear optimization. The stochastic inversion uses a stratigraphic/structural framework to define the 1-ms micro-layering to be enforced by the inversion results. Input data consisted of: (1) four partial angle stacks and angle-dependent wavelets for the following angle ranges: (6-16), (16-26), (26-36), and (36-46) degrees; (2) lithotype, P-velocity, S-velocity, and density logs, and (3) well-log generated geostatistical information in the form of variograms and lithotype-dependent 3D joint PDF's of the acoustic properties to be inverted (P-velocity, S-Velocity, and density).

Figure 3 shows the results of the AVA stochastic inversion, consisting of high-resolution (1 ms) 3D distributions of lithotypes (sand/shale), P-velocity, S-velocity, and density. Figure 4 is a comparison between the high-resolution stochastically derived acoustic impedance (sampled at 1ms) and deterministic inversion results generated using a constrained sparse spike inversion (CSSI) algorithm (sampled at 4 ms).

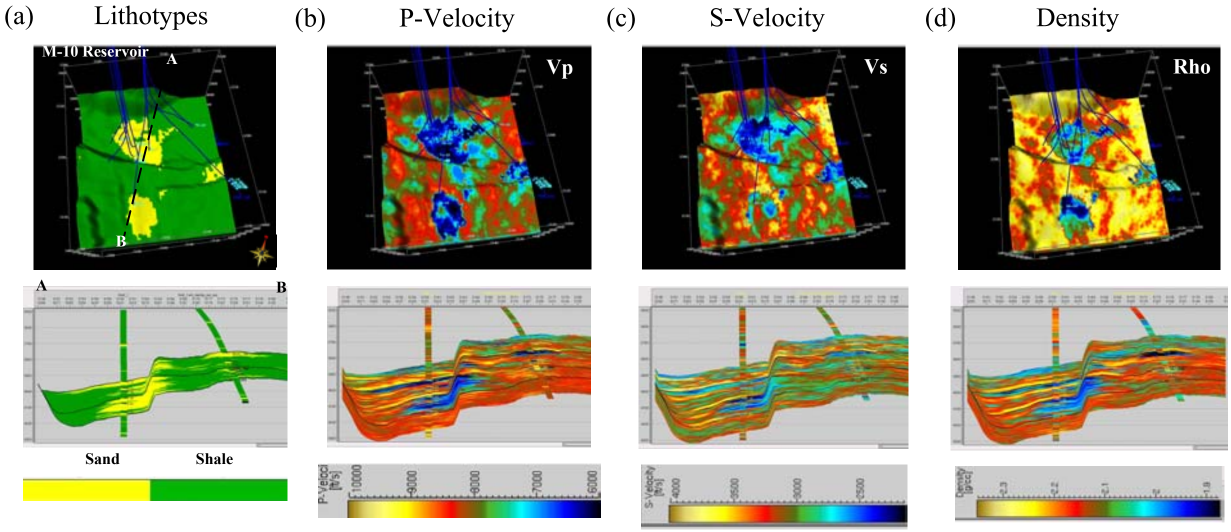

Figure 3. AVA stochastic inversion results: (a) Lithotypes (sand/shale); (b) P-Velocity; (c) S-Velocity; and (d) Density. The spatial coverage is approximately 4 km^2, and the vertical interval: 3500-4300 ms.

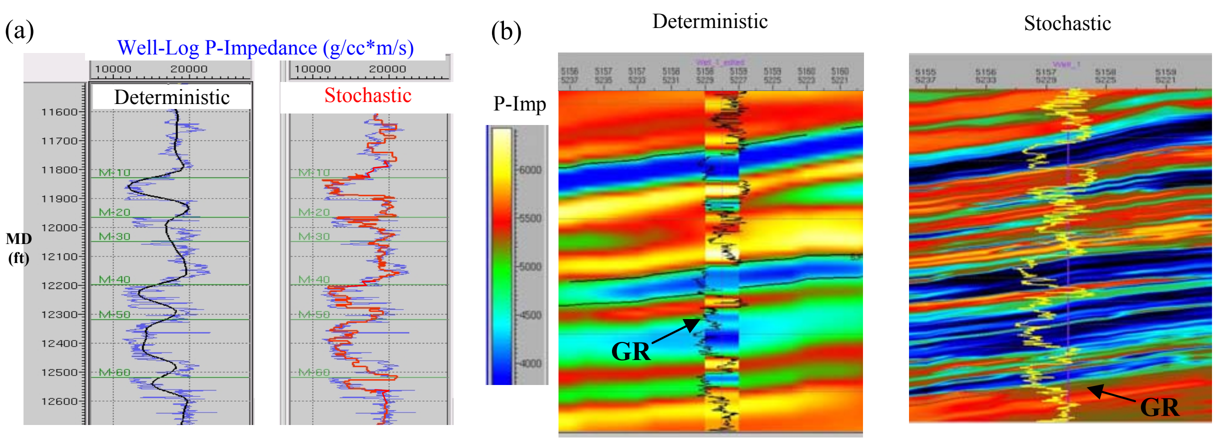

Figure 4. Deterministic versus stochastic inversion results: (a) inverted P-impedance pseudo logs extracted at a well location; (b) inverted P-impedance cross-sections. Deterministic results are sampled at 4 ms whereas stochastic inversion results are sampled at 1 ms. Vertical interval: 3800-4300 ms.

Co-Simulation of Petrophysical Properties

Finally, 3D spatial distributions of petrophysical properties (porosity, permeability, and water saturation) were constructed via co-simulation of the AVA stochastic inversion results using multivariate statistics. Figure 5 (a) is an example of the layer- and lithotype-dependent multidimensional joint probability distributions of acoustic and petrophysical properties used for co-simulation. The use of multivariate statistics to relate acoustic and petrophysical properties such as P-velocity, S-velocity, density, porosity, permeability, and water saturation, allowed us to construct accurate 3D distributions of petrophysical properties, especially when compared to similar distributions constructed with empirical linear relationships and/or cloud transforms.

(a) 3D Joint PDF (b) Porosity (c) Permeability (d) Water Saturation

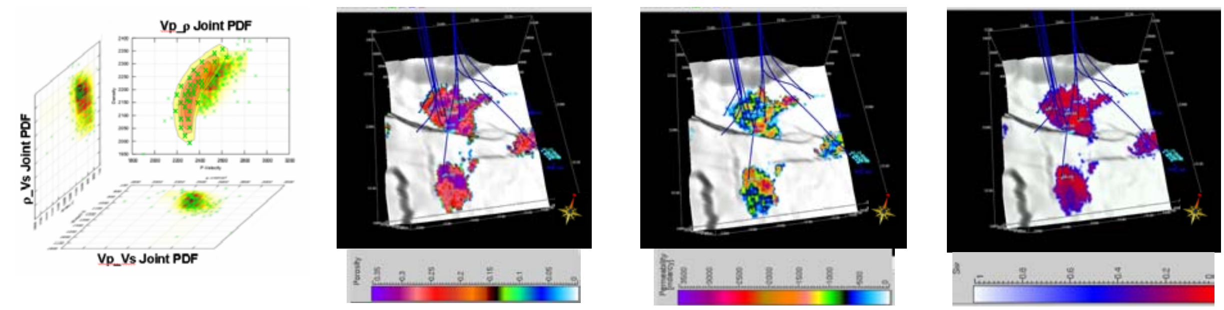

Figure 5. (a) 3D joint PDF of acoustic properties (six properties were used for co-simulation: P-Velocity, S-Velocity, density, porosity, permeability, and water saturation). (b), (c), and (d) Co-simulated porosity, permeability, and water saturation, respectively, for the M-10 reservoir.

Conclusions

Standard AVA analysis indicates that the shale/sand interface at the top of the M-series reservoirs generates significant AVA anomalies. On the other hand, Biott-Gassmann fluid substitution indicates that presence of low density pore fluids clearly affects the elastic response of sands. Accordingly, joint stochastic inversion of pre-stack seismic and well-log data provides quantitative information about the spatial continuity of reservoir units and of their pore fluids. Pre-stack stochastic inversion provides more realistic and higher vertical resolution results than those obtained with analogous deterministic techniques. Furthermore, 3D petrophysical models can be more accurately co-simulated from AVA stochastic inversion results. By combining geologic information with AVA sensitivity analysis techniques and pre-stack stochastic inversion it is possible to substantially reduce development risk associated with non-conventional reservoirs.

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References

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