

Optimizing the reservoir model of delta front sandstone using Seismic to Simulation workflow: A case study in the South China Sea

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Summary

The South China Sea contains approximately 11 billion barrels (bbl) of oil reserves (EIA, 2013). Offshore development requires detailed understanding of subsurface reservoirs and proper well placement. Use of all available information in an integrated reservoir model leads to improved production rates and higher EUR. Conventional methods use well logs, geologic information, and structure from seismic interpretation in static reservoir models, which, in turn, predict future production and evaluate alternative management scenarios. However, these models, which use different data types in isolation, often fail replicate past production (history matching).

An integrated seismic-to-simulation workflow is presented in this paper; dense 3D seismic data provide a great deal of lateral lithofacies and rock-property information that is essential to the static model.

A seismically constrained geomodel (a.k.a. geostatistical inversion) is the cornerstone of this workflow. Using rock physics and geologic knowledge, we performed geostatistical inversion to generate a series of high-resolution lithofacies and reservoir property cubes. After strict blind well tests and dynamic simulation to optimize processes and parameters, we developed a static model that integrates logging, seismic, geology and dynamic data. The resulting reservoir model matches existing production, distribution and heterogeneity of the reservoir, residual oil, and location of “sweet spots”.

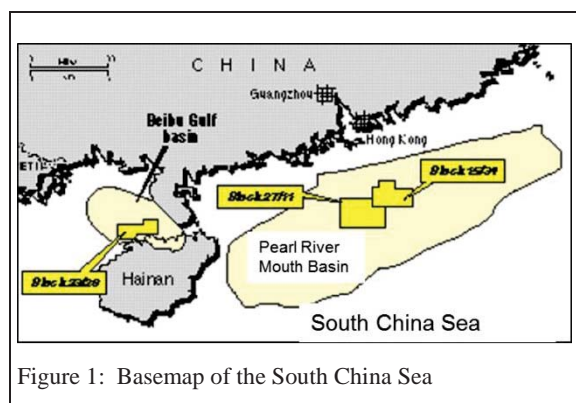


Figure 1: Basemap of the South China Sea

Introduction

The Panyu low-uplift is located in the Pearl River Mouth Basin of the South China Sea (Figure 1). This study focuses on building a superior static reservoir model of a Middle Miocene sandstone. This reservoir is a delta-front sand with high porosity and permeability, containing intermediate gravity oil. Reservoir and associated facies consist of sandstone, calcareous sandstone and shale. Oil-column height of the target zone is less than 20 meters, requiring structural accuracy in order to successfully exploit the play and estimate reserves.

Conventional methods used to generate static reservoir models rely on a geologic and stratigraphic framework, using seismic data to fill in structural details. This is followed by geostatistical modeling using wells – but not seismic – to constrain the static model. These models typically may not match current production and oil saturation in the initial run, but could match production with manual intervention (a.k.a. porosity or permeability modifiers). Nevertheless, these modified models may fall short in prediction of bottom-hole pressure, residual oil saturation, reservoir heterogeneity, and remaining oil in place.

Utilizing well log, seismic, geologic, and dynamic data individually to build a conventional reservoir models only serves to highlight conflicts between these disciplines. For example, well data cannot effectively replicate the structure of reservoirs because wells are unevenly distributed and may be biased toward favorable reservoir properties. Therefore, 3D seismic information needs to be introduced for effective integrated modeling, not only for the structural framework, but for facies distributions and selected reservoir properties as well.

Methodology

Forty square kilometers of 3D seismic and 35 wells are used in this study, one of which contains a dipole sonic log. Five horizontal wells penetrate the target zone.

An iterative, integrated workflow was created, as shown in Figure 2, to achieve the objective of creating a better static reservoir model without manual intervention. Iteration can occur in selected parts of the process, if dynamic simulation

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does not match production history, such as adjustment of geologic structure and geostatistical inversion.

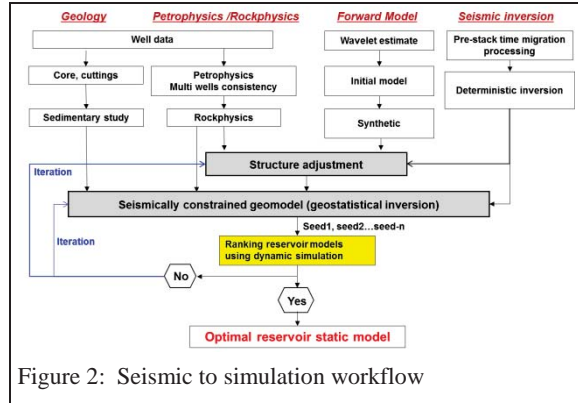


Figure 2: Seismic to simulation workflow

(1) Analysis of geological sedimentation

The Middle Miocene Sandstone is a transgressive delta-front subfacies, controlled by regional faulting. Figure 3a shows the main, mid-west trap zone. Log curve profiles, funnel and approximately box-shaped, are typical of subaqueous distributary channels. The curves also display a combination of multiple funnel and bell shapes, attributed to mouth-bar micro-facies. These depositional signatures suggest the reservoir distribution should be relatively predictable. Figure 3b shows that calcite increases to the east with associated degradation of reservoir properties.

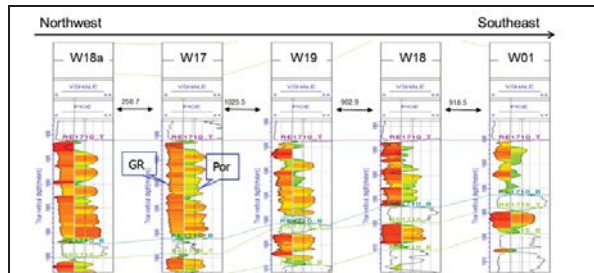


Figure 3a: Stratigraphic correlations

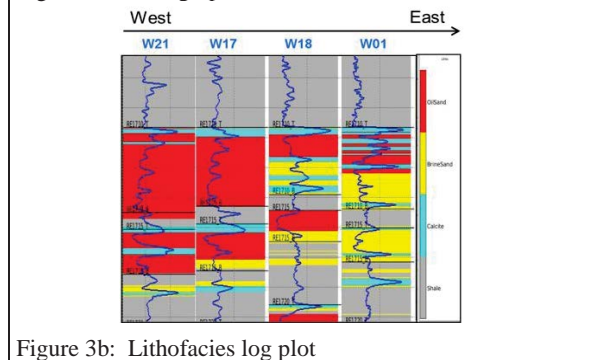


Figure 3b: Lithofacies log plot

(2) Petrophysics and rock physics

Petrophysics aims to provide multiple log curves with consistent quality within wells and reasonable trends between wells (Zhang et al, 2014). A workflow incorporating single-log quality evaluation with geological input and multi-well normalization procedures was established in order to calibrate and correct inconsistencies in measurements. Wavelet estimation and well-tie correlations with seismic improved afterwards.

The well with dipole sonic measurement facilitated creation of an elastic forward model based on “log feature correlation analysis” and “differential effective medium theory” (Norris et al, 1985). A template was developed using well data and cores to determine porosity, saturation, mineral volumes and elastic relationships (Figure 4). Sandstone exhibits low P-impedance and low Vp/Vs, while mudstone has higher P-impedance and Vp/Vs. As calcite increases, the P-impedance and Vp/Vs also increase. The chart shows that lithofacies can be distinguished by P-impedance and Vp/Vs on a log scale.

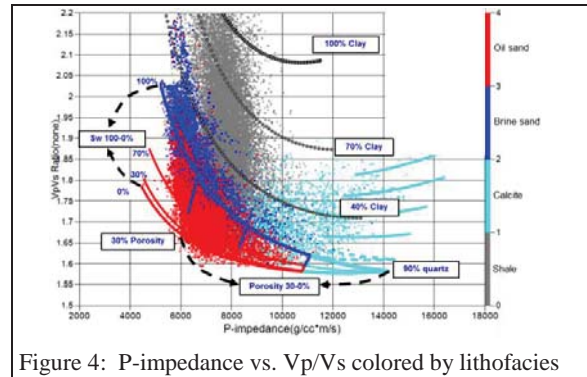


Figure 4: P-impedance vs. Vp/Vs colored by lithofacies

3. Seismic analysis with forward model and structure study

Figure 5 suggests the target sandstone disappears to the southeast on the 3D seismic data, where there are no wells present. It is uncertain whether this is caused by sand pinch-out or for other reasons. If real, this reduces the trap area, thereby affecting reservoir volumetrics and the results of dynamic simulations.

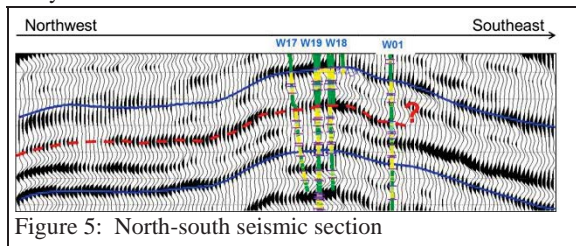


Figure 5: North-south seismic section

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Reflectivity characteristics of the seismic were carefully analyzed from a forward model based on corrected well logs, the wavelet extracted from well ties, and sedimentary analysis. The geologic assumptions implied in the forward model are, (1) reservoir distribution is relatively predictable, and (2) calcite increases to the east and is associated with decreasing reservoir quality. This model provides the framework for understanding the rock physics and elastic responses associated with the reservoir.

Figure 6 shows that the forward model response is similar to the actual seismic data. It demonstrates that the Middle Miocene Sandstone does not pinch out to the southeast, although calcareous sandstones similar to those found at W01 in the east are present. The seismic reflection of the sandstone top changes from its expected signature of low impedance to high impedance in the southeast. The structure of the target zone was reinterpreted as positive in the southeast, and trap area subsequently increased by 8%.

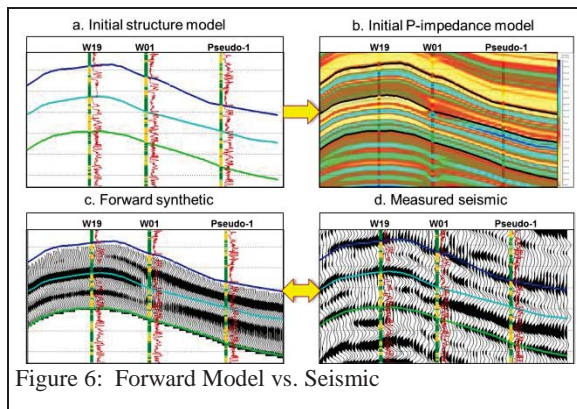


Figure 6: Forward Model vs. Seismic

(4) Geostatistical inversion

Wedge modeling shows that tuning thickness is 16m, implying that deterministic inversion can only detect reliable thickness down to 8m. Because many sand packages in this area are known to be thinner than 8m, geostatistical inversion is employed so that more-granular details can be detected using well statistics, while accounting for “sub-seismic” uncertainty. Geostatistical seismic inversion uses a Bayesian Markov Chain, Monte Carlo (MCMC) technology (Wang et al, 2015). This method facilitates imaging the heterogeneities of the reservoir properties and lithofacies which may exist below seismic resolution, through multiple realizations, each of which honors the seismic.

Figure 7a shows the vertical lithofacies proportions from the geostatistical inversion. Prior proportions represent the percentage of each lithofacies as it appears in control wells.

Posterior proportions are extracted from inverted 3D volumes. This shows more calcite in the unconstrained area (the black box in the figure 7a). This is consistent with geologic understanding, well logs, and forward models.

Blind well testing is a powerful quality control tool, used to validate and optimize geostatistical parameters. Figure 7b shows about 95% correlation between blind wells and sand probability derived from geostatistical inversion. The thickness map of sand and calcareous sand is relatively stable, becoming thinner towards to southeast, consistent with geological analysis (Figure 7c).

Geostatistical inversion volumes, converted to depth, provide lithofacies and impedance cubes. Effective porosity is co-simulated from relationships between impedance and porosity. From effective porosity and lithofacies volumes, permeability is characterized in the 3D volume. Saturation is generated from a J function (Leverett et al, 1941) which was calibrated by core data.

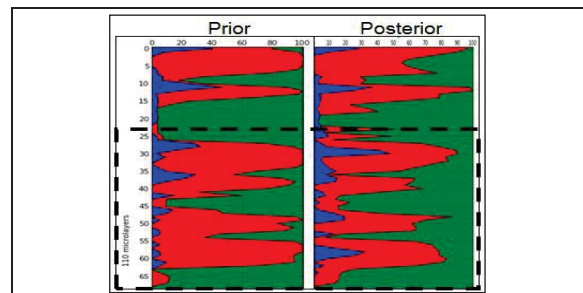


Figure 7a: Vertical Proportion- Input vs. Output

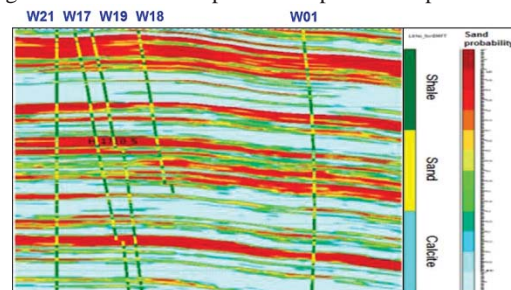


Figure 7b: Blind wells overlaid on probability volume

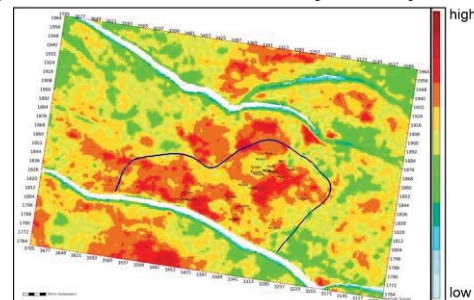


Figure 7c: Sand thickness map from geostatistical result

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(5) Reservoir simulation

Iterations between modeling and simulation are difficult using conventional modeling methods; therefore the seismic-to-simulation workflow was used to perform model ranking and dynamic calibration in this study. The ultimate goal of this workflow is having a good production history match in the initial run, without manual intervention.

Comparison of reservoir simulations using conventional and seismic-to-simulation workflows highlight several important differences. The conventional model effectively simulates water-cut, but does not accurately predict bottom-hole pressures, which have not changed significantly after decades of production (left panel, Figure 8). The original model does not consider the influence of calcite, or structural complexity indicated by seismic. Bottom-hole pressure are stable enough and matches the measured pressure data in the revised model when both of these factors are taken into account (right panel, Figure 8), as the influence of calcareous sandstone facies alone does not completely resolve the pressure mismatch (middle panel, Figure 8). History-matching is also very good (right panel, Figure 8).

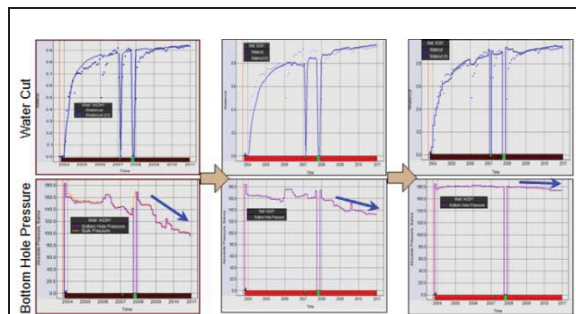


Figure 8: Comparison of water cut and pressure for different reservoir models

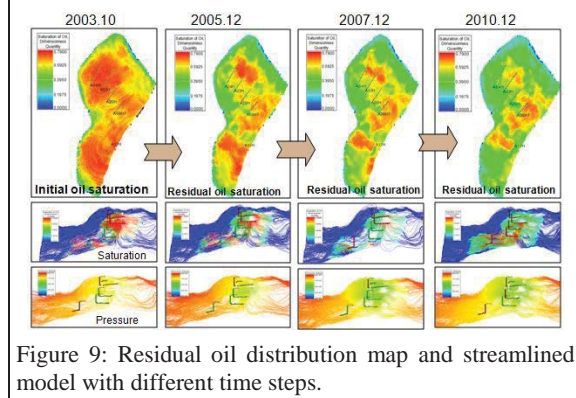


Figure 9: Residual oil distribution map and streamlined model with different time steps.

A series three dimensional, seismically-constrained, subsurface models were generated via geostatistical inversion. An optimized static model was generated from the ranking of these individual realizations. Dynamic simulation used this static model to produce a streamlined model which shows fluid-flow characteristics, injection and production relationships, and waterflood-front position at different time steps. It also maps residual oil distribution (Figure 9). Areas of higher and lower residual oil demonstrate the heterogeneous nature of reservoir and the effective radius of producers. In the target zone, the original oil saturation was 0.66; the mean of present residual oil saturation is 0.52 according to the simulation results. These results are being used in designing an overall development program to maximize recoverable reserves.

Conclusions

Each discipline in isolation contributes incomplete and sometimes incompatible information about the reservoir; therefore, conflicts are inevitable. The iterative seismic-to-simulation workflow provides a new angle for understanding discrepancies between various disciplines. Through rock physics, forward modeling, and geological analysis, reservoir characteristics of the Middle Miocene sandstone are more predictable. Benefits include reduced structural uncertainty, confirmation of the trap area, improved understanding of reservoir heterogeneity and distribution of lithofacies away from well control. Reservoir properties are consistent with logs, seismic, geology and dynamic reservoir information. The workflow efficiently integrates multi-discipline information in a quantitative manner. The trap area, reservoir volumetric, and residual oil were calculated over the entire 3D model. The optimized static model selected from dynamic simulation determines residual oil distribution and sweet spots.

This workflow creates an accurate static model necessary to reduce risk for development well locations, and assists in planning full field development. The workflow also provides a better understanding of the complex offshore delta-front sandstone, and enables more efficient and, hence, cost-effective development.

Acknowledgments

The authors would like to thank CNOOC (China) Panyu Operating Company for permission to publish this work and Kevin Chesser at CGG GeoConsulting for providing critical reviews.

EDITED REFERENCES

Note: This reference list is a copyedited version of the reference list submitted by the author. Reference lists for the 2016 SEG Technical Program Expanded Abstracts have been copyedited so that references provided with the online metadata for each paper will achieve a high degree of linking to cited sources that appear on the Web.

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