A reservoir characterization study in the Burgos Basin including simultaneous prestack inversion and lithology prediction

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Summary

In this paper, we present a reservoir characterization study in the Burgos Basin, onshore northeastern Mexico which includes a spatial lithology distribution based on lithoclasses generated using rock physics and Bayesian statistics. The lithology prediction is preceded by prestack simultaneous AVO inversion. The method of inversion is based on simulated annealing and composed of a globally optimized algorithm which simultaneously inverts a number of angle stacks and their corresponding wavelets. The outputs include volumes of acoustic and shear impedances as well as Vp/Vs ratio. The study was carried out in order to determine the lateral extent of the producing gas-saturated sand which has been penetrated twice successfully based solely on seismic amplitudes. The characterization work performed using well log data and the inverted volumes has enabled accurate mapping of pay sands in the study area and refined the prediction of future drilling targets.

Introduction

Within the past ten years, there has been an increased interest in performing prestack inversion due to the capabilities of extracting both P and S wave information from P wave data acquisition (Ma, 2002). The inversion process converts seismic data to layer properties including acoustic impedance (AI), shear impedance (SI), Vp/Vs ratio, Poisson's ratio, density, lambda-rho and mu-rho. These properties may then be used to generate volumes of lithology, water saturation, porosity, volume of clay and net-to-gross.

The field of study is within the Burgos Basin in northeastern Mexico. The basin is a Tertiary coastal basin that represents the southern extension of the Texas Rio Grande embayment. It encompasses the area extending from the city of Matamoros to the town of Soto La Marina. The depositional history of the field is complex. The main reservoirs are comprised of sand facies from the Paleocene Midway formation. The trap mechanism is identified as stratigraphic and defined by lobe-like geometries resulting from gravitational processes during the tilting and subsidence of the subjacent carbonate platform over which the Midway Formation was deposited. The seal is conformed by interdigitated argillaceous sediments also from the Midway formation.

Two wells with compressional and shear sonic, density and other conventional logs exist in the study area. The third well has no measured shear and is therefore used only for quality control. The zone of interest is composed of a sequence of gas-saturated sands between 15–30 meters in thickness. The inversion results were taken a step further to produce a spatial lithology distribution based on lithoclasses generated using rock physics and Bayesian statistics.

Method

The inversion process converts seismic data from interface properties to layer properties such as acoustic impedance and Poisson's ratio. The inversion engine utilizes a global optimization algorithm with a non-linear cost function to simultaneously invert a number of input stacks to an earth model. The inversion is based on a convolutional model, generating synthetic seismic data via an iterative process which seeks to reduce the error between observed and modeled seismic. The algorithm uses a modified version of the Aki & Richards (1980) reflectivity approximation.

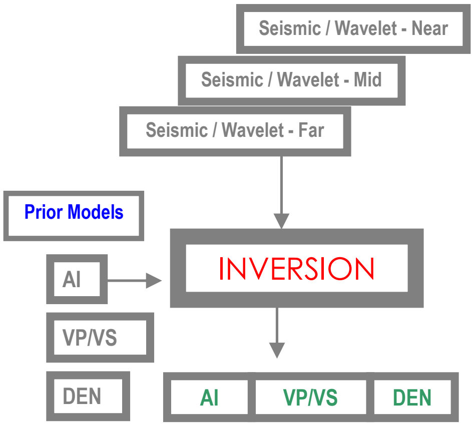

Figure 1: General simultaneous AVO inversion inputs and outputs.

The key steps in the process are seismic and well log pre-conditioning, well calibrations, wavelet extraction, prior model building and finally, the inversion. Initially, the offset gathers or stacks are analyzed and any necessary pre-conditioning steps are performed which may include noise and multiple suppression, amplitude balancing, and gather flattening. In addition, the well logs are edited in order to remove errors due to cycle skipping, washouts and other potential problems not corrected for during the initial processing. Once the logs and seismic data are fit to undergo inversion and the angle stacks are generated, the available wells are calibrated and wavelets are extracted. The wavelet suite which exhibits the most consistent phase stability about all the angle stacks and maximizes the correlation between seismic and synthetic is initially chosen. The starting model in this iterative process is generated from well log data, interpreted horizons and interval velocities. Finally, the data undergo inversion where the outputs are produced and analyzed (Figure 1).

Datasets and inversions

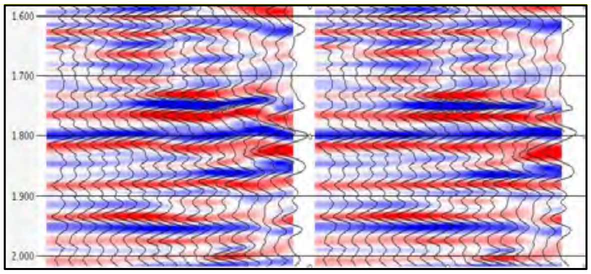

Figure 2: Offset gather before (left) and after (right) alignment for reservoir zone at Well B.

A proper QC of seismic data prior to inversion is a key component in any seismic reservoir characterization workflow. The available offset gathers showed insufficient residual moveout correction. In addition, an assessment of the PSTM velocity field and the velocity profiles from the processing of two VSPs in the study area revealed significant differences at shallow depths, which confirmed that the seismic velocities needed to be modified. An alternative to re-picking the velocity field using a more sophisticated process (i.e. high order, two parameter anisotropy) was to align the data in the gather domain without compromising neither the phase nor the frequency using a proprietary algorithm. The standard approach is to align the angle stacks using the near stack as the reference. However, the severe residual NMO issue previously mentioned made it necessary to align the data prior to angle stack generation.

The alignment process consists of sorting the NMO corrected CMP gathers into offset planes (Figure 3). For each plane, a 'raw' displacement field is computed using the previous offset as the reference. Next, a final displacement field for each offset is calculated and applied by summing all the previous 'raw' displacements, After all the time shifts have been taken into account, the final displacement field is filtered within the range of 6-10 Hz in order to smooth existing abnormal values. Finally, the data is sorted back into the CMP gather domain. Once the gather flattening was satisfactorily achieved, the CMP gathers were stacked into 4 angle stacks (in degrees, angles of 5-12, 12-19, 19-26 and 26-33).

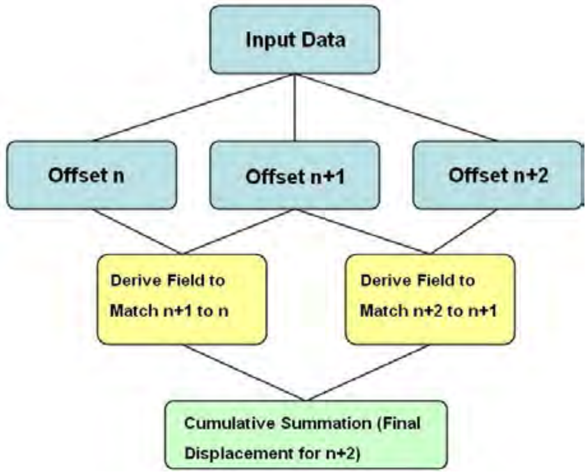

Figure 3: Workflow diagram for gather flattening in CMP gather domain assuming only three offsets exist.

In our inversion approach, independent wavelets are estimated for each angle stack. Variations in frequency, phase and amplitude between the different seismic input stacks is captured by the wavelets, so there is no need for scaling, phase rotation or frequency balancing of the seismic data. The wavelet analysis showed that maintaining the phase information from the seismic data was possible, therefore the phase spectrum was derived from the correlation between the seismic and well log data. Using a multi-well wavelet utilizing the reflectivity from both producing wells (Well A and Well B) showed a significant improvement in the inversion results at all wells. If a single well wavelet suite were to be chosen, the result at that well would be better, but at the cost of sacrificing the results at all other wells. Well C never penetrated the reservoir therefore was omitted from the wavelet estimation process.

Figure 4 shows the multi-well wavelets extracted from the producing wells. The first three angle stacks produced consistent wavelets without time delays. The last stack (angle 26-33) had a small time delay which had no impact on the AI inversion result. On the other hand, keeping the far stack degraded the match at the reservoir for the Vp/Vs result. This is due to the fact that Vp/Vs information comes from the mid to far angles. Since there was not enough angle coverage to invert for density and the loss of resolution in Vp/Vs, the far angle stack was dropped.

The low frequency models were generated by extrapolating the filtered logs using a 10 Hz low pass filter, guided by the interpreted horizons and interval velocities. Since the shear sonic log was not measured for Well C, a fourth well (Well D) at the edge of the survey was introduced in addition to wells A and B. Well D is also a producing well, but from a different reservoir. Its sole purpose was to provide more control in the prior model building process.

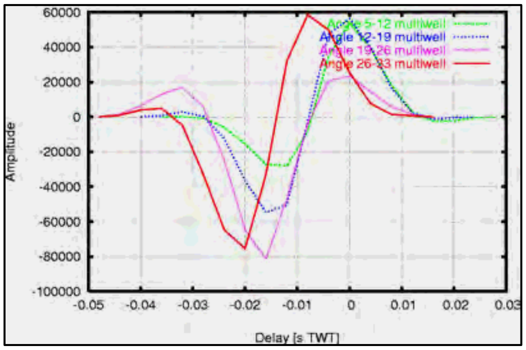

Figure 4: Multiwell wavelets from wells A and B for all four angle stacks.

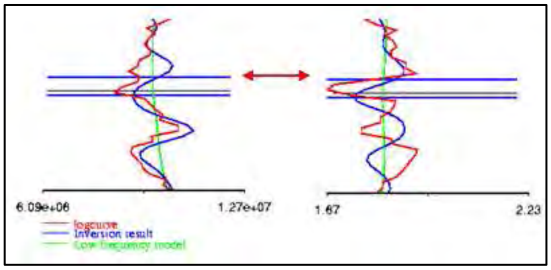

Figure 5: AI (left) in Kg/m^2s and Vp/Vs (right) inversion results at Well B. Reservoir top is indicated by double red arrow.

The inversion result for acoustic impedance was in good agreement when comparing the match between the well log and inverted trace. Although the Vp/Vs inversion result was not as good as the AI (Figure 5), it accomplished identifying the gas, which is of prime importance for achieving success in the lithology prediction. Figure 6 shows a horizon slice at the top of the reservoir sand for Vp/Vs. The result shows two separate delineated bodies; the larger body has the two producing wells within it. The smaller body was missed by Well C. Based on seismic attributes, it was originally believed that the reservoir zone was one laterally extending body (Figure 7), which was the basis for how the location of Well C was determined.

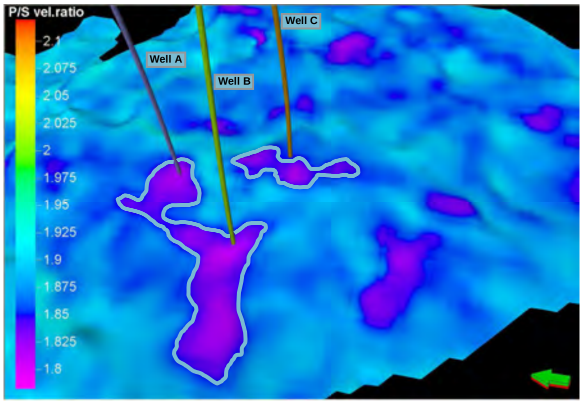

Figure 6: Horizon slice (top of the reservoir sand) for the Vp/Vs inversion result. All three well trajectories are shown.

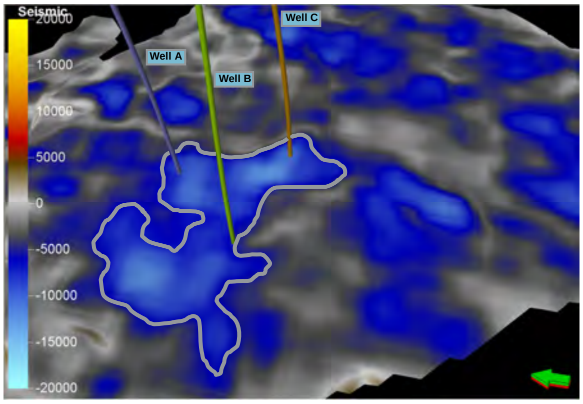

Figure 7: Horizon slice (top of the reservoir sand) for the stacked seismic data. All three well trajectories are shown.

Well data and lithocube analysis

Log data from the two wells available in the studied area were used in the rock physics analysis. A suite of logs, including compressional and shear sonic (DT, DTS) and density (RHOB), was available. In addition, clay volume (VCL), total porosity (PHIT), effective porosity (PHIE) and water saturation (Sw) with conventional logs such as caliper, gamma ray and resistivity were used.

The quality of the logs, mainly compressional and shear sonic as well as density, were evaluated using rock physics models such as Hashin-Shtrikman (1963). Such models provide a quick evaluation of DT, DTS, and RHOB logs, which are the main inputs to the seismic inversion workflow. These models, together with caliper, VCL, PHIE and Sw logs, can show intervals with bad log quality which may then be edited using the appropriate method.

The lithology and fluid distribution of a hydrocarbon reservoir is mainly controlled by the depositional system and geological setting favorable for hydrocarbon generation and accumulation. Rock physics and AVO trends are dependent on lithology and fluid properties. Lithofacies may be classified using elastic attributes. Hence, the rock physics analysis of the well log data was made to evaluate the capability of seismic attributes such as acoustic impedance and Vp/Vs ratio to discriminate the lithology and fluid content of the reservoir sand and the surrounding shales. Figure 8 is an AI versus Vp/Vs cross plot clearly showing a separation between hydrocarbon bearing sand from non pay. In our analysis, we used Vp/Vs ratio, AI and SI for predicting hydrocarbon bearing sands.

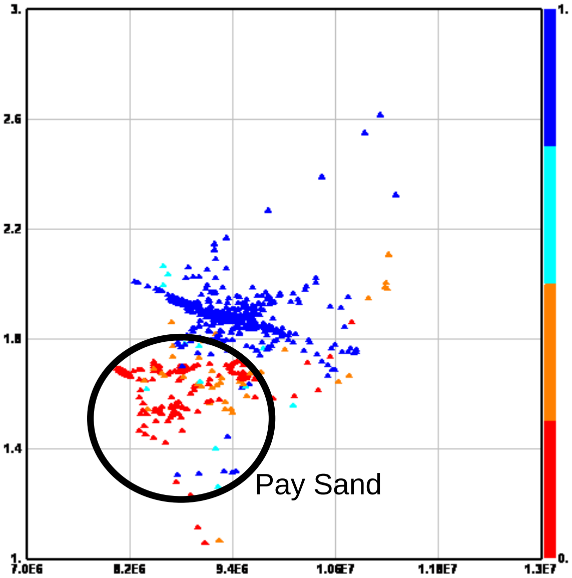

Figure 8: Cross plots of AI versus Vp/Vs color-coded by SW for both producing wells (Well A and Well B). Water saturation increases from blue to yellow.

The petrophysical properties VCL, PHIE and Sw together with sonic and density logs were used to diagnose the rocks and establish lithoclasses (i.e. pay sand and shale). Probability density functions (pdfs) generated from the well log data were applied to the seismic inversion cubes to produce class and probability cubes. The methodology is discussed in Sengupta and Bacharach (2007).

Figure 9 is a map view of pay sand probability at the top of the reservoir. The results are interpreted as: given the information known from the wells A and B, there is an 88.0% probability that hydrocarbons exist at Well A, which is where we know the well is producing; the same goes for Well B, which shows a 61.5% probability. In Well C (the blind well), we know there are no hydrocarbons and has a 47.6% probability. One may assign a conservative threshold of ~55% - 60% to determine whether gas-saturated sand is present or not.

The quality of the log data and inversion results will dictate how trustworthy the lithocube results really are. In areas where the inversion results correlate poorly with the logs, the lithocube result must be carefully analyzed. The highest confidence lies where the correlation is highest between inversion results and measured logs.

Conclusions

The reservoir characterization study showed the integration of prestack simultaneous inversion results along with the existing geological knowledge of the Burgos Basin onshore eastern Mexico. These results have accurately predicted the presence of in-situ hydrocarbons at the wells used in the study, accurately mapping pay sands that can be used for risk mitigation in the future planning of drilling targets.

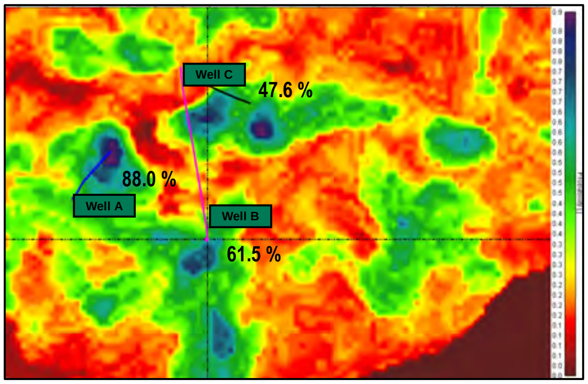

Figure 9: Map view of pay sand probability at the seismic interpretation representing the top of reservoir with corresponding values.

Acknowledgements

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EDITED REFERENCES

Note: This reference list is a copy-edited version of the reference list submitted by the author. Reference lists for the 2009 SEG Technical Program Expanded Abstracts have been copy edited 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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