



Estimation of facies and fluid probabilities in a field of Krishna-Godavari offshore basin from pre-stack inversion results

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Summary

Interpretation of deterministic inversion does not prognosticate the inherent uncertainties in the data, so essentially any interpretation of inversion data should be probabilistic. Deterministic inversion followed by probabilistic interpretation approach is more desirable. Probabilistic interpretation incorporate in a systematic way all major factors contributing to the inherent uncertainty associated to reservoir models. In this study, facies and fluid probabilities of reservoir sand was determined from pre-stack seismic inversion data to estimate the probabilities of lithology using joint probability density functions (pdf). A joint/multivariate pdf was generated to model the statistical relationship between multiple properties from deterministic inversion using Bayesian probability theory in clastics reservoir sand in a field of Krishna-Godavari offshore basin. Rock physics analysis of logs was done and multivariate probability density functions (pdf) were computed from well logs of P impedance and Vp/Vs for reservoir properties defined by lithofacies. This classification gives four facies volume of oil, gas & brine sand and shale. The aim of this study is to quantify the uncertainty of different lithofacies estimated from inversion results.

Introduction

The Facies and Fluid Probabilities (FFP) study facilitates a quantitative interpretation, along with uncertainty estimates. So it is very useful in derisking and ranking prospects and pre-drill assessment. The derived volumes will tell us likelihood of occurrences of pay sand at a particular location. The basic input for this study is pre stack inversion volume of P impedance and Vp/Vs ratio and Rock Physics Modelled (RPM) logs. Rock physics Diagnostics (RPD) is normally used to detect hydrocarbons and lithofacies (Dvorkin et al, 2003), but it cannot quantify the uncertainties that are associated with the natural variability in the data. Pre-stack inversion integrates the information of the seismic, log and relevant geological information available in terms of structure as well as stratigraphy. Discrete lithotypes are generated from the logs of the wells within the target zone. So each sample of the well log represents one of the lithotypes. The objective of

this study is to estimate the facies and fluid probability volumes of oil and gas from the pre-stack seismic inversion data of a field of Krishna-Godavari Basin, east coast of India, **Fig: 1**. Out of ten wells, nine wells are producing hydrocarbon in the study area. These rock physics modelled logs were tied with seismic data. The thickness of hydrocarbon bearing sands in this area varies from 0.5m to 42 m. The best combination to discriminate the oil and gas sand from brine sand and shale are through P-impedance vs. Vp/Vs cross plot of logs that segregate the different lithologies. The logs data are filtered in seismic frequency band to investigate the probability of discrimination of lithologies from inverted seismic data. The thick pay sand are discriminated in seismic frequency band, however thin sand are not.

The joint probability density function (pdf) is created for each lithotype from the crossplot of P impedance and Vp/Vs logs, color-coded by the lithotypes. The classified pdfs based on facies are applied on these 3D inversion volumes to estimate facies probabilities, followed by analysis performed to validate these intervals of hydrocarbon sand in the drilled well positions in the study area.

Seismic Inversion

The principal input for this study is pre-stack seismic inversion volumes. The core of the pre-stack inversion is a constrained sparse spike inversion (CSSI) algorithm. The elastic models generated from constrained sparse spike inversion are absolute. The pre-stack simultaneous inversion algorithm determines the optimum combination of P-impedance, S-impedance, Vp/Vs, and density to explain the AVO response of the seismic angle stacks. This inversion was carried out using three angles stacks generated within the range of 6 to 42 degree. The use of three angle stacks simultaneously results in reduced sensitivity to noise in the input seismic data. Important information used for pre stack inversion is wavelet, extracted from well-to-seismic tie. The inversion accounts for both wavelet amplitude and phase spectra. The P impedance and Vp/Vs volumes of inversion were used for the estimation of facies and fluid probabilities. The section view of these volumes through the wells with logs overlay is shown in **Fig: 2**.

Estimation of facies and fluid probabilities from pre-stack inversion results

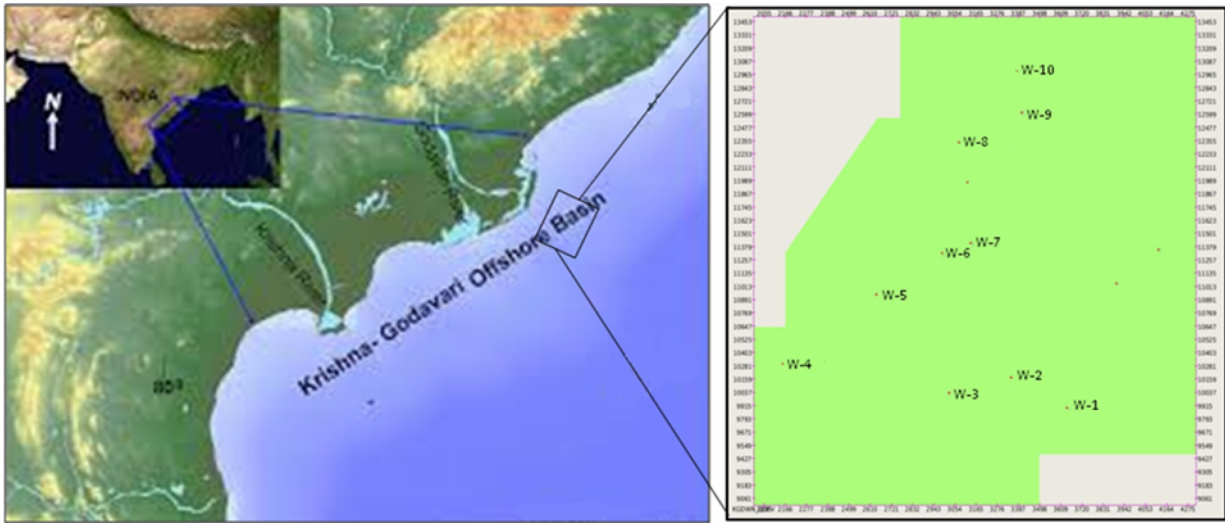


Fig.1. Location map of Krishna-Godavari offshore Basin and our study area.

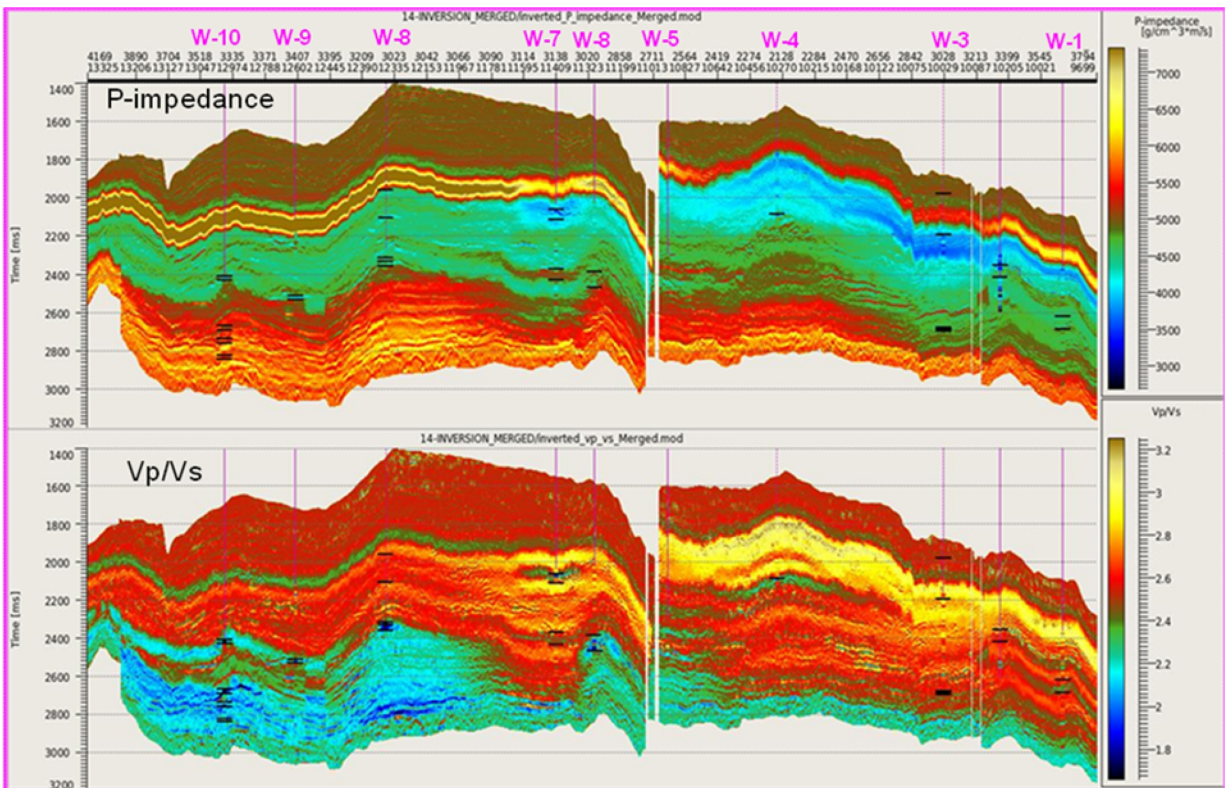


Fig. 2. Inverted P-Impedance and Vp/Vs through the wells, overlain with respective logs. The perfect matching of well data with inversion result indicates good inversion result.

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Methodology to estimate Facies and Fluid Probabilities

The methodologies adopted for estimation of this facies and fluid probabilities are as follow:-

1. **Definition of lithofacies from logs:-** We defined four lithofacies of oil sand, gas sand, brine sand and shale representing distinguishable characteristic w.r.t petrophysical properties such as clay content, bedding configuration, grain size, cementation, density, and velocities. This was the basis for quantitative facies and fluid estimation.

2. **Cross plot and joint pdf:-** Before creating crossplot and joint pdf, the prior probabilities are estimated for each of selected lithotypes with known geological information. Cross plot was taken between P-impedance and Vp/Vs of well logs that was filtered to the inversion bandwidth and color-coded by the well lithology to create a joint pdf for each facies, **Fig: 3**.

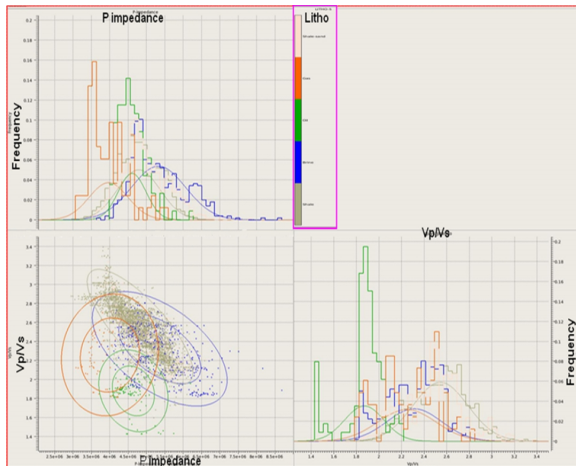


Fig: 3. Cross plot of P impedance Vs. Vp/Vs (left corner) and the histogram of corresponding logs. PDF are selected for four litho types. The histograms represent the distribution of data values in the logs, colored by lithology for each elastic parameter.

3. **Editing and QC of the pdfs:-** Using the cross plots and histograms, pdfs are fitted for each lithotype to statistically model each lithotype. The pdfs created from the well data are applied to the inverted data. To avoid one lithotype with a very small probability, an extra lithotype is used called Unclassified, with the associated prior probability that is used as threshold. The QC was done to the original wells and compared with the original lithology log. The pdf are then applied to the inversion results along the QC trace gate and adjusted the unclassified prior value based on this QC and final result was decided, **Fig: 4**.

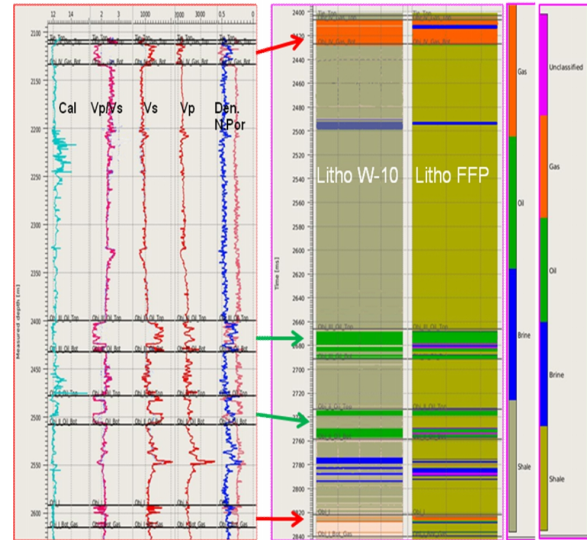


Fig: 4. Two gas sand (top & bottom) and two oil sand (middle) of well W-10 showing litho logs from well and FFP result.

4. **Application of the pdfs:-** We applied the lithology pdfs to the inverted seismic attribute volumes to estimate the most likely facies, and the probability of occurrence of each facies at every grid point within the cube. At each data point the probability of the present lithologies are estimated.

Evaluating the FFP results

The most probable lithology occurrence is envisaged by comparing all lithology probability volumes. The vertical section through well W-10 showing probability upto 60 to 70 percent oil in object III, and 40 to 50 percent in object II which are oil producing sand. The gas sand is showing 60 to 70 percent probability of gas in this well. The percentage of shale in these pay levels are 10 to 20, **Fig: 5**. Similarly, analyzing of W-8 well indicates 70 to 80 percent gas in top and 60 to 70 percent oil in base of the pay sand, **Fig: 6**.

Volume of Hydrocarbon

The volumes of probable pay sand of this area are extracted from the probable oil and gas sand volumes. The areal distribution of probable oil sand and gas sand are shown in map view, **Fig: 7**. It is observed that more than 10m thick pay sand are only captured by this study while thinner sands could not be brought out.

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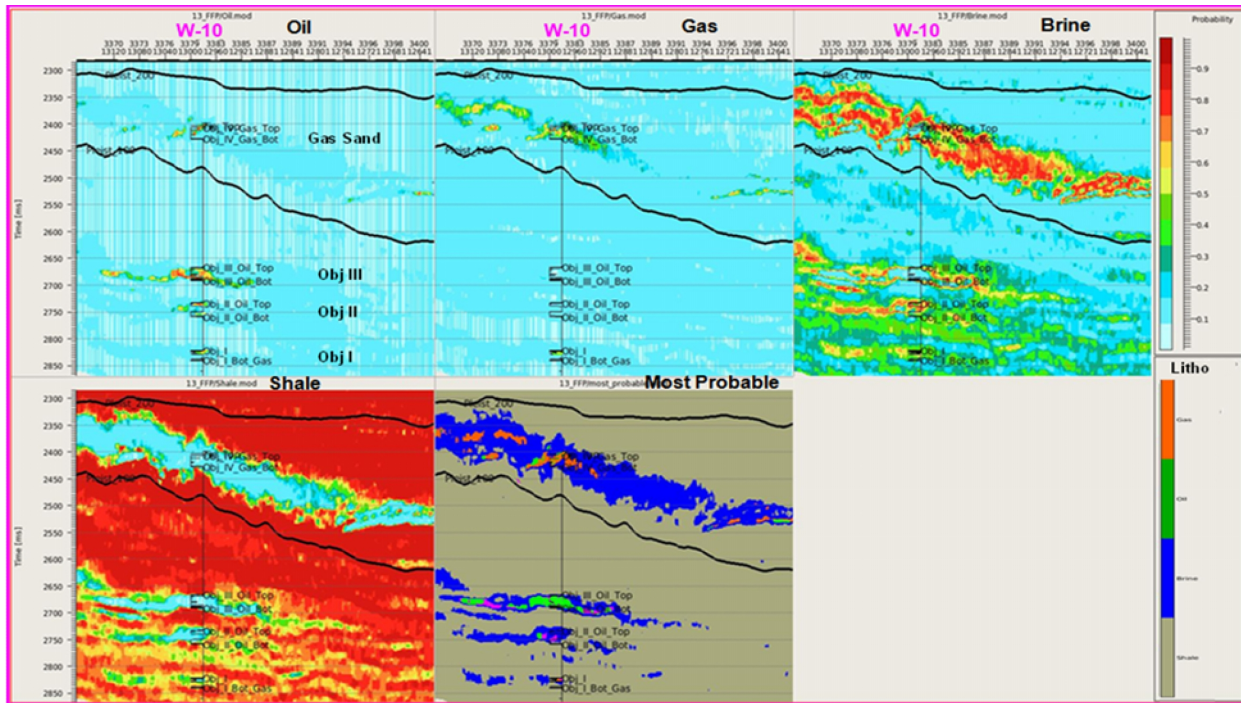


Fig. 5. Vertical section passing through well W-10, showing most probable oil, gas, brine sand and shale.

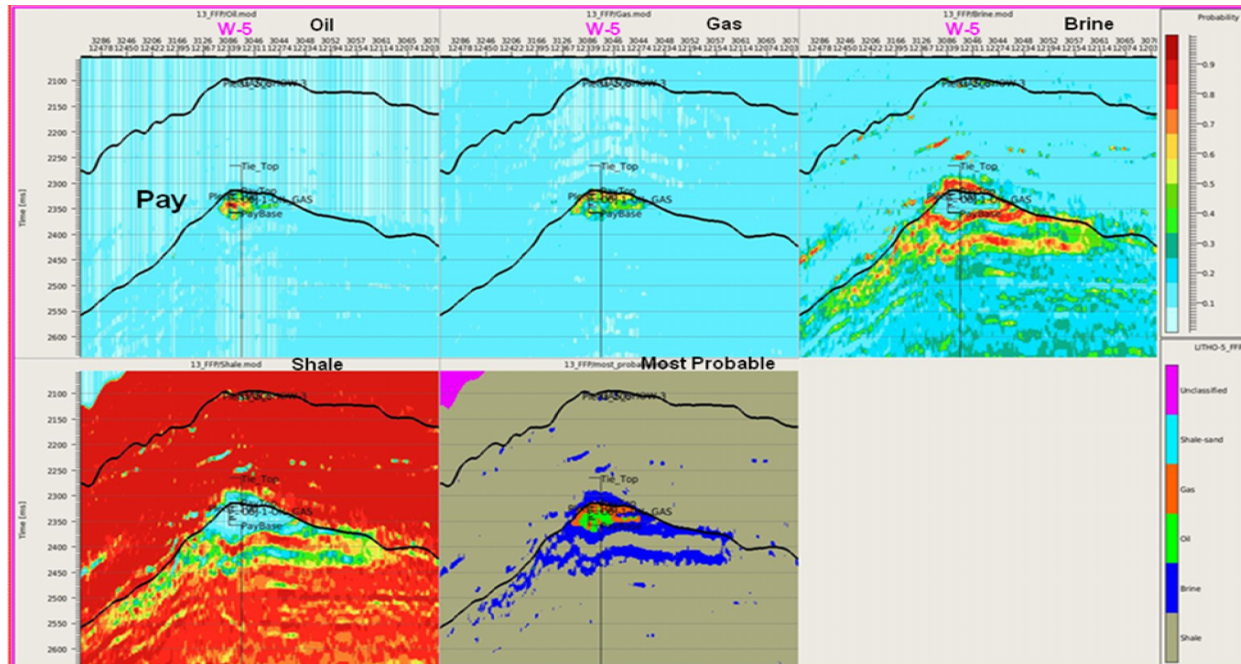


Fig. 6. Vertical section passing through well W-8, showing most probable oil, gas, brine sand and shale.

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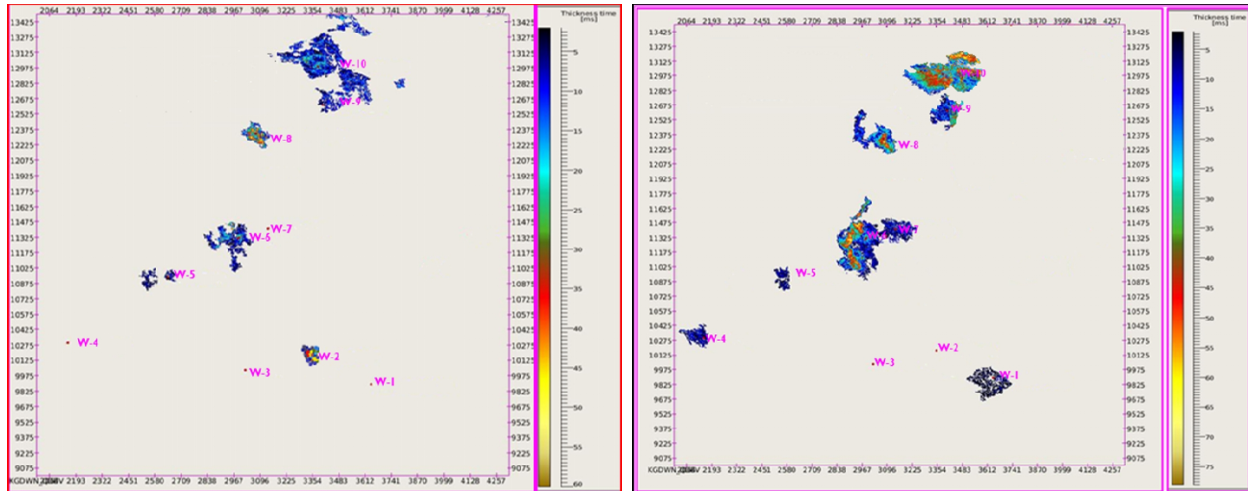


Fig: 7. Areal distribution of oil sand (left) and gas sand (right) extracted from probable oil and gas volume respectively.

Conclusions

Estimation of subsurface property from indirect geophysical measurements is always subject to uncertainty because of many inevitable difficulties and ambiguities in data acquisition, processing, and interpretation. So it is required to quantify the information content, and uncertainty in rock property estimation from seismic data. This kind of technique is used to investigate the probability of occurrence of the oil and gas sands which validates the observed oil and gas sands and indicates probability of occurrence of similar anomaly elsewhere. This facies and fluid probabilities study can be used as a quantitative interpretation tool that estimates the uncertainty in reservoir. So it is very useful in derisking prospects and pre-drill assessment. However estimation of probable oil and gas sand from thin sand may not be possible from pre-stack seismic inversion data. Moreover, these results are partially affected by overlapping properties of pay and brine sands and thinness of reservoir sands. Detailed petrophysical study and improved seismic processing is essential for more convincing results.

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