# Lithology Prediction from Seismic Data: An Integrated Approach

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## Summary

Estimating variation in reservoir properties from seismic data is a key challenge in exploration and appraisal. Integrated reservoir characterization using several attributes extracted from the seismic data to build a probabilistic lithology presence maps has been discussed here.
The Vijaya & Vandana (V&V) area lies south east of the producing Aishwariya field along the Eastern Margin of the Barmer Basin, situated in western Rajasthan.(Fig-1).Conventional seismic studies were carried out in V&V area to predict the gross lithology and outline of the channel complexes. However, individual channels cannot be resolved due to limited seismic resolution. The seismic data has limited vertical resolution which in turn introduces uncertainties in reservoir fairway delineation. It is evident that no single methodology can provide a full description of the reservoir characteristics. In order to create the most comprehensive reservoir understanding, an integrated reservoir characterization becomes important.

## Introduction

Barmer Basin, situated in western Rajasthan, (Fig-1) is a low strain, NW-SE trending, 200 km long and 25 km wide, failed continental rift and northward extension of the Kutch or Cambay basin. The basin contains Jurassic to Recent sediments overlying Proterozoic basement. The basin suffered multiple phases of rifting and later inversion and tilting during the Himalayan orogeny (Dolson et.al, 2015). The Vijaya & Vandana (V&V) area lies south east of the producing Aishwariya field along the Eastern Margin of the basin. Twelve wells have been drilled in the V&V graben, which shows good reservoir development in the lacustrine Barmer Hill Formation. The lithology of this interval is predominantly laminated siltstone, coarser beds of siltstone, argillaceous sandstone and conglomerates of turbidite origin, deposited against the background canvas of shales and porcellanites (Kothari et al, 2016). It exhibits distinctly different channel and mounds morphology in seismic data as compared to the layered porcellanites of the Aishwariya field.

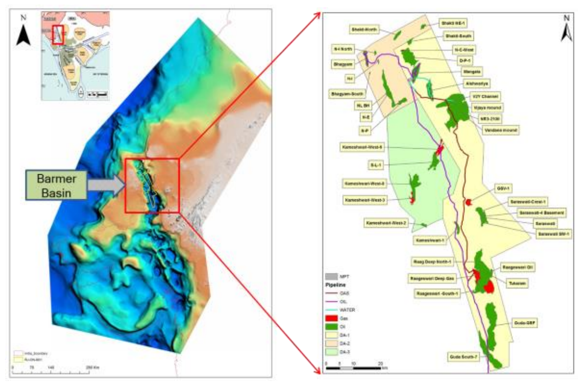


Figure-1: Location map of study area

A perceptible change from high amplitude, continuous seismic reflectors of layered porcellanites of adjacent Aishwariya field to low amplitude, chaotic 'mounded' seismic facies are observed in 3D seismic data of V&V area (Fig-2). The V&V mounds exhibit several key turbidity-flow depositional elements, including channel complexes, associated channel elements and depositional lobes. Delineation of these channel sands, controlled mainly by the channel geometries (length, width, sinuosity, which in turn affect the facies distribution, reservoir continuity and overall NTG of the system), thus stands out as the most prominent sub-surface uncertainty in the estimation of hydrocarbon volume.

Several parameters like gross thickness, seismic amplitude and seismic facies characterizing the lithofacies were studied which fundamentally used seismic data (pre-stack gathers & stack volume) and well data

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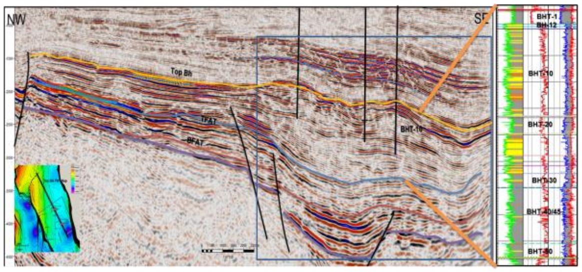

Fig-2: Representative seismic section and a typical well log

Rock physics analysis has established that Vp/Vs is the key elastic property discriminating reservoir from non-reservoir. Simultaneous inversion was carried out to obtain Vp/Vs volume which delineates reservoir fairway at seismic scale. Gamma Ray log being fairly representative of reservoir lithology, Multivariate Statistical analysis was carried out on seismic and inverted volume traces to derive Gamma ray Volume. The results from these studies were combined to produce reservoir presence probability maps.

This reservoir prediction integrated with seismic mapping and forward modeling, seismic multi-attribute analysis, waveform classification and seismic inversion techniques gave better picture of lithological boundaries with higher confidence .

## Methodology and Key parameters Defining Reservoir Presence

Seismic attribute and forward modeling studies revealed that reservoir fairway can’t be deciphered with a standalone attribute. Hence multiple methods were applied to delineate the high reservoir areas. And the results from these seismic based reservoir prediction methods were combined to produce probability maps of reservoir. Following parameters were studied to define the reservoir presence-

***Gross Thickness**:*

Seismic Interpretation suggests presence of mounded features at BHT10 reservoir level which is understood to be formed from amalgamation of channels and exaggerated by syn and post depositional soft sediment deformation process. (Fig-2).Twelve wells were drilled in the area which shows that there is a fair bit of correlation between net pay and gross thickness and generally higher gross thickness is resulting into higher net pay. Hence gross thickness derived from seismic interpretation and wells is one of the key determinants of the net sand thickness in this area.

***Amplitude:***

Acoustic impedance is not a discriminator of lithology for BHT10 reservoir. Hence the interfaces in seismic are not necessarily lithological boundaries and amalgamated responses of sands and shale are observed in seismic. Several scenario based 1D forward modeling was performed and possible controls on amplitude were studied (Fig-3). Based on the result, the RMS amplitude map is interpreted for reservoir presence and polygons are defined for area with higher probabilities of reservoir presence.

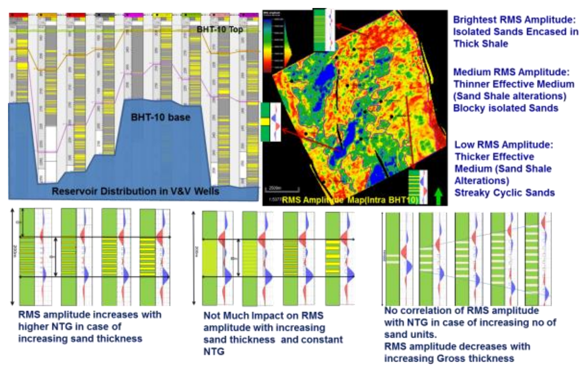


Fig-3: Forward Modeling for Amplitude Variation helped to derive the best guess model for sand distribution and identify the high reservoir areas based on RMS amplitude map.

***Waveform Classification:***

The waveforms were analyzed in a narrow interval of seismic data along the top of the reservoir section (BHT10 Top) and compared to template waveforms supervised by wells. Waveforms were classified into 5 classes based on the template waveforms assuming that similar waveform will represent similar geology in terms of lithology and facies. Waveform Classification assigns a class number to each waveform in the defined interval. Interval follows a horizon and usually of constant length to avoid thickness complications. Waveform maps are thus generated where the similar waveforms are grouped together in classes, so edges and regions appear sharp and clear compared to amplitude and frequency based attribute maps. Reservoir fairway was identified on waveforms map within BHT10 and areas were high graded based on these polygons (Fig-4).

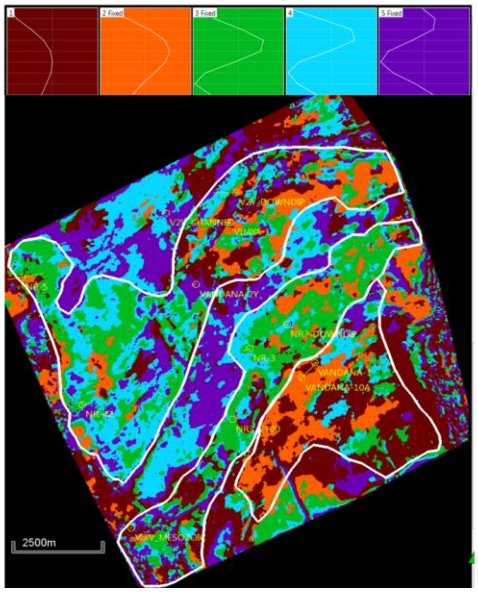


Fig-4 Waveform Classification showing channel belt and Fan geomorphology.

***Inverted Vp/Vs:***

Vp/Vs is a reasonable discriminator of sand and shale in this area and Seismic data is a prime source of information on reservoir heterogeneity between the wells.

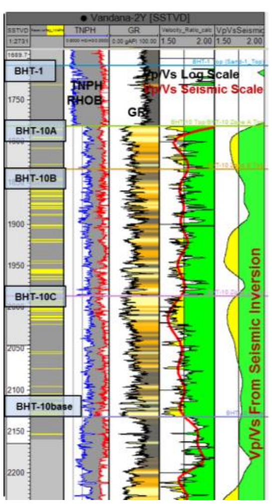


Fig-5 : Inverted Vp/Vs showed reasonable match with seismic bandwidth filtered well derived Vp/Vs

Pre Stack Inversion of the seismic data allowed extraction of shear impedance along with acoustic amplitude. The derived Vp/Vs showed reasonable match with well data (Fig-5) and gave a better control of sand distribution within the area.

Careful calibration of the volume with the well data helped to identify the extension of low Vp/Vs or sandy areas within BHT10. (Fig-6)

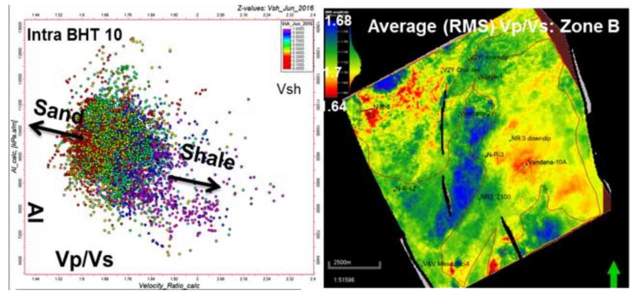


Fig-6 Left part is a cross plot of AI Vs Vp/Vs colored with Vshale and sandy part within BHT 10 is highlighted by low Vp/Vs. Right Side map shows delineated sand rich area at seismic scale.

The Inverted Vp/Vs helped to delineate high and low quality reservoir areas spatially between wells at seismic scale.

***Multi Variate Statistics:***

Various methods were explored to use Pre Stack inversion results to constrain reservoir distribution.

Although Vp/Vs separates sand from shale reasonably, gamma ray (GR) log is a better separator of lithology hence in this methodology it was aimed to predict Gamma Ray from seismic data, inverted data and attribute volume of both (Hampson et al, 2001) The multi attribute transform is defined combining a set of seismic attributes into a desired target attribute log.

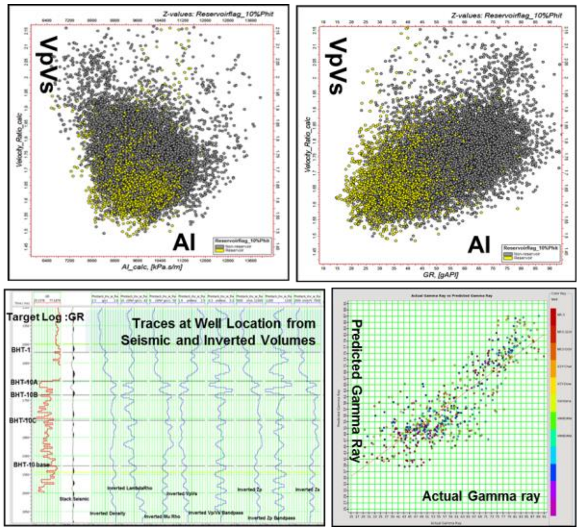


Fig-7 Upper part shows the Gamma Ray as better indicator of reservoir compared to Vp/Vs (yellow color represent reservoir in the well). Gamma Ray derived using multi variate statistics on seismic and inversion outputs.

The optimal solution is derived by exhaustive search among all possible combinations. The derived GR volume delineates high reservoir and low reservoir areas in seismic resolution scale.

## Integrated reservoir characterization

Each study resulted in reservoir fairway polygon, different to one another in terms of geometry and extent. However these polygons from individual studies have considerable overlap. All these polygons were then superimposed to identify high, medium and low confidence areas for presence of the reservoir. The area where all polygons overlap is considered as high confidence and low confidence area being derived from overlap of less than two polygons. These high, medium and low confidence maps were then converted into probability maps and used for making net sand maps and as a soft trend in facies modeling.

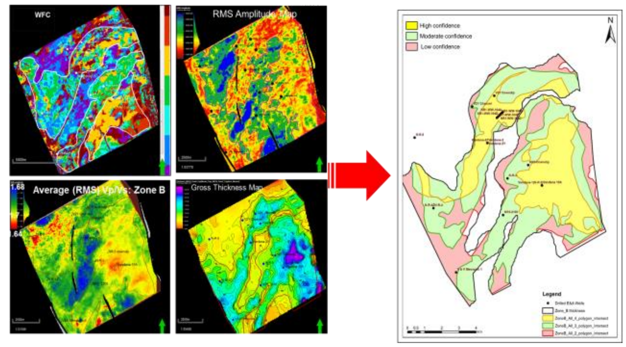


Fig-8 Deriving Sand Probability map combining all methods.

## Conclusion

Based on seismic forward modeling and preliminary seismic attributes in the V&V area, standalone seismic attributes were unable to provide a high confidence solution to delineate reservoir fairway. A new approach has been adopted whereby combining multiple geophysical attributes viz. gross thickness, waveform analysis, RMS amplitude, pre-stack inversion Vp/Vs volume and multivariate GR volume, confidence areas were defined. Along with that, the net sand found in the drilled wells was also taken into account to prepare probability maps of reservoir presence which was used in static modeling.

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