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Application of Geomechanics and Rock Property Analysis for a Tight Oil Reservoir Development: A Case Study from Barmer Basin, India

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Summary

Hydraulic fracturing of low permeability reservoirs requires identification of sections along wellbore with good reservoir and completion quality. Completion quality depends on the poro-elastic properties of the reservoir. Geomechanical modeling and characterization is one of the key components to get the desired fracturing results. This paper describes the approach undertaken in Barmer Hill Formation in Barmer Basin, Rajasthan to improve the efficiency using laboratory characterization of mechanical properties on core, core-log integration and continuous mapping of reservoir properties using seismic attributes along and away from wellbore.

Keywords: *Geomechanics, Low Permeability, Seismic Attributes, Tight Oil*

Introduction

E&P industry is focusing more and more on exploiting low permeability and challenging reservoirs. Hydro-fracturing is the major technology to maximize production from these reservoirs. Step by step learning from the different fields proved the importance of detailed reservoir characterization incorporating rock quality and completion quality. The rock quality governs the hydrocarbon storage properties whereas completion quality depends on the poro-elastic properties. Successful hydraulic fracturing of low permeability reservoirs requires identification of reservoir sections along the wellbore with good reservoir and completion qualities. Elastic properties govern in-situ stress field, stress concentration around wellbore and failure properties of the units, which leads to hydraulic fracture geometry and propagation behavior. Geomechanical modeling and characterization is one of the key components to get the desired fracturing results.

Geological Setting

The Barmer Basin is a NNW-SSE oriented rift basin situated in the northwestern part of India in the state of Rajasthan. The sedimentary sequence in this block is of

Cretaceous/Paleocene-Eocene age. Cairn is the operator of Rajasthan Block RJ-ON-90/1. Mangala, Bhagyam and Aishwariya are three major fields situated in the northern part of the block. Throughout the basin, the Barmer Hill Formation overlying the main oil producing clastic Fatehgarh Formation. The Barmer Hill Formation comprises inter-bedded siltstones and siliceous mudstones and minor sandstones.

In general terms, the Barmer Hill Formation is interpreted to have been deposited in a lacustrine setting with subsidiary marginal fluvial fans and fan deltas along the western and eastern margins of the rift.

Although the main prolific reservoir is Fatehgarh Formation, in northern part of the basin the shallower low permeability Barmer Hill Formation contains significant hydrocarbon resources. In the northern part of the basin, the Barmer Hill Formation is 50-250m thick and upper part of the formation is characterized by a low gamma and high resistivity log response with well-developed hydrocarbon signatures.

Barmer Hill Formation contains significant intervals of laminated micro-crystalline quartz rich sediment. The origin of this high siliceous input is interpreted to be

biogenic evidenced from diatoms in outcrop samples from the northern part of the Barmer Basin. Diatoms would have originally been deposited as opaline silica (Opal-A), which has transformed with depth and pressure to microcrystalline quartz in the subsurface (Chowdhury et al., 2011). As these rock types are diagenetically altered and generally have an indurated, fine grained appearance the textural term “porcellanite” (Boggs, 1995) has been adopted.

Barmer Hill Formation underlies the Dharvi Dungar Formation which is the regional seal. During the exploration and appraisal phase of the fields, hydraulic fracturing treatments were carried out in Barmer Hill porcellanite reservoirs (Shaoul et al., 2009). It has been proved that hydraulic fracturing is a viable means to produce the oil to surface and develop the field economically.

Methodology

The spatial distribution of reservoir properties within and across each unit guides future horizontal well orientation, placement and fracture design. Reservoirs were differentiated by mineral composition integrating petrophysical log data and elastic properties which was used to infer brittleness of each unit. The data were used as input to geo-mechanical modeling and near / far wellbore stresses were estimated.

Elastic rock properties and seismic were subsequently integrated into a seismic inversion process delineating areas of optimum reservoir properties, thus identifying potential zones for hydraulic fracturing.

Near Wellbore Characterization

Rock Characterization

The reservoir rock dominantly comprises of microcrystalline quartz that has undergone phase changes from opal to quartz with change in pressure and temperature during burial. Clay and organic matter forms millimeter scale layers within the reservoir as shown in Figure 1 and Figure 2. Clay rich layer and organic rich layers have different elastic behavior. This results in contrast in properties between directions parallel and perpendicular to bedding planes. This difference in texture of clay and organic matter affects the elastic rock properties.

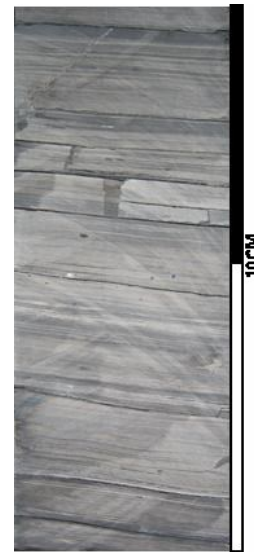


Figure 1: Thin lamination of micro-crystalline quartz alternating with clay & organic rich layers observed in conventional core.

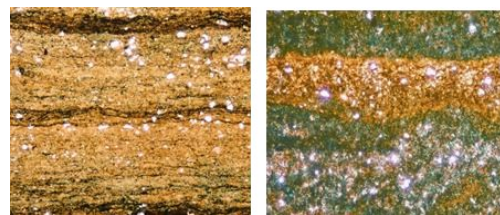


Figure 2: Microscopic scale heterogeneity (lamination) seen in petrographic thin section. The light color are the quartz dominated layers while the dark color are the organic and clay rich layers.

From the integration of conventional core and image log data, it was established that in the northern part of the basin the Barmer Hill Formation includes a distinct millimeter scale laminated silica-rich lithofacies. These laminated units are of high porosity (25-35%) but have low mobility ratios (0.01-0.30 mD/cp).

Figure 3 shows the XRD analysis results of the reservoir units. The target reservoirs have higher quartz content and low clay content. Among the clay minerals, kaolinite is dominant with minor proportion of illite/chlorite clays. These clays are not so chemically reactive to hydration during coring process. However, care was taken to minimize effect of coring fluids and to maintain the integrity of the rock during coring.

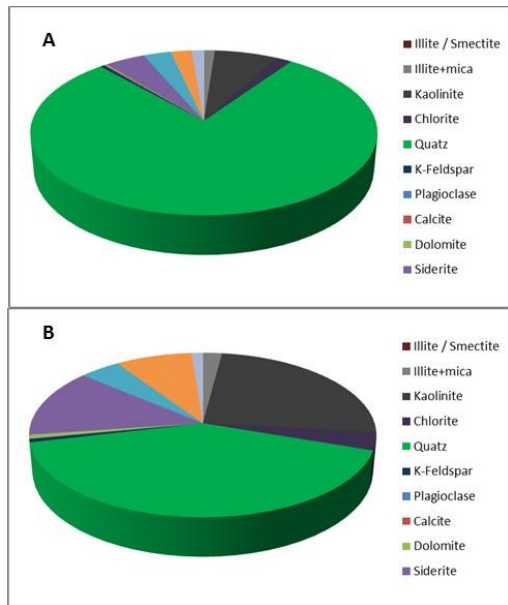


Figure 3: XRD derived mineralogical constituents. A. represents the quartz (dark green) dominated (80%-90%) rock. B represents the non-reservoir rock with quartz (40% approx.) and kaolinite (grey) as the major clay mineral.

Laboratory Analysis

Geomechanical laboratory test on cores are the most comprehensive means to derive the mechanical properties. Low permeability rocks require slow loading rates and therefore tests on these samples can be very time consuming. Considering all these challenges and uncertainty in results, the mechanical tests were carried out in Barmer Hill Formation at reservoir pressure and temperature conditions in two cycles of loading and unloading process. Mechanical properties including Compressive Strength, Young's Modulus and Poisson's Ratio were measured on core plugs.

Log derived Compressive Strength, Young's Modulus and Poisson's Ratio were calibrated to lab measurements as shown in Figure 4A & 4B.

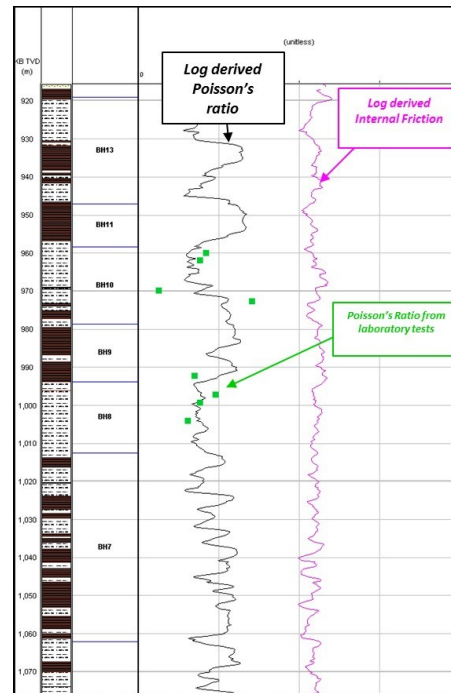


Figure 4A: Calibration of log derived Poisson's Ratio with core measured data

The calibrated data were used to define the brittleness of the rock. Figure 5 represents the inferred brittleness coefficient as a function of Young's Modulus and Poisson's Ratio. Compared to conventional quartz rich reservoirs (Slatt et al, 2011), these layers show low brittleness due to the micro-crystalline nature and mode of origin.

In Barmer Hill Formation, the region with brittleness coefficient greater than 60, i.e., higher Young's modulus and low Poisson's Ratio were characterized as the most suitable zones for hydraulic fracturing.

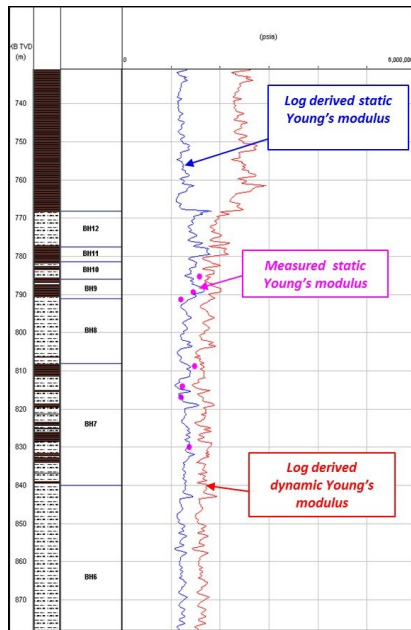


Figure 4B: Calibration of log derived Young's modulus with core measured data

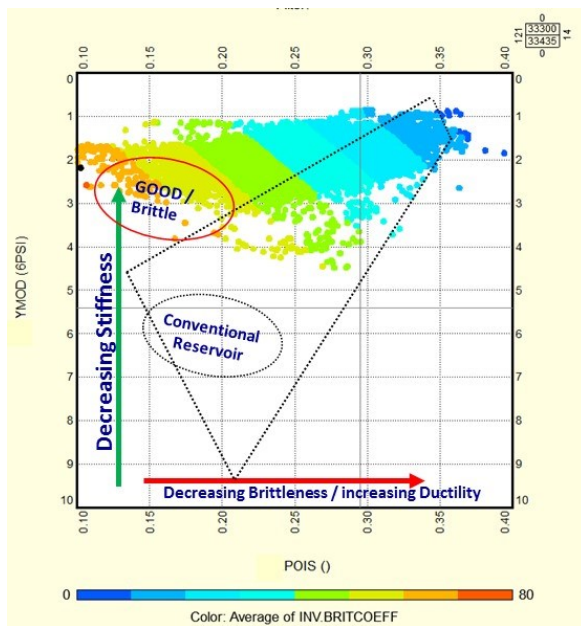


Figure 5: Plot of Young's Modulus (YMOD) and Poisson's Ratio (POIS) for 22 wells. Conventional tight reservoir tend to fall within the black (dotted) region. Zones suited for fracturing is indicated in red circle (orange data scatter).

Far Wellbore Characterization

Determination of stress regime

Horizontal stresses result from far field deformations and change from facies to facies as a result of their contrast in elastic properties.

Minimum Horizontal Stress was estimated using Leak Off tests (LOT) carried out in number off wells during exploration. Bottom hole pressure-time plots were used to estimate the fracture closure pressures. The closure pressures were interpreted at 0.615psi/ft although some pressures were obtained at 0.7psi/ft. On examination, it was seen that in addition to anisotropy, localized heterogeneity is observed in cores, wellbore images and mineralized fractures. The mineralized fractures are hairline or slightly bigger in width. They can intersect the wellbore and cause release of pressure in the near wellbore region.

Maximum Horizontal stress orientation was obtained using shear sonic data. The fast shear direction is in clear alignment to $N10^{\circ}/N190^{\circ}$ ($\pm 10^{\circ}$) as shown in Figure 6. Multiple zones of formation breakout were observed from image logs in vertical wells (Chowdhury et.al, 2011). Wireline micro-frac tests were conducted in multiple reservoir layers within the formation of interest. Drilling induced fracture orientation was also used to model the rock strength. This rendered the range from 18 – 24 ppg.

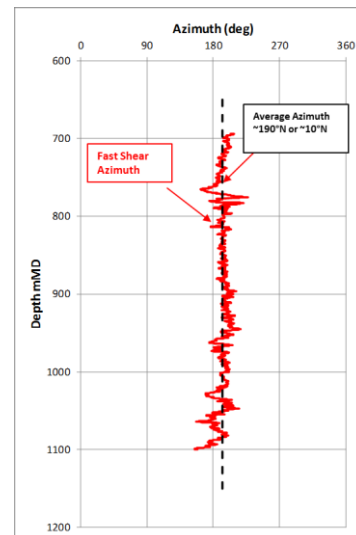


Figure 6: The fast shear direction is in clear alignment to $N10^{\circ}/N190^{\circ}$ ($\pm 10^{\circ}$) as the maximum horizontal stress direction.



Vertical Stress was determined using the density and sonic logs. Logs are available from 100m below the ground level. An exponential curve is used to approximate density from the ground level. Normal compaction trends were determined using the sonic log. Very limited low confidant pressure measurements were available due to the tightness of the formation. Pore-pressure estimation was done using the pressures measured by formation testers in the underlying and overlying formation. The hydrostatic pressures were found to be normal of 0.433 psi/ft. integration of both data provided the effective stress magnitude.

Figure 7 summarize the modeling results of different stress profile and pore pressure.

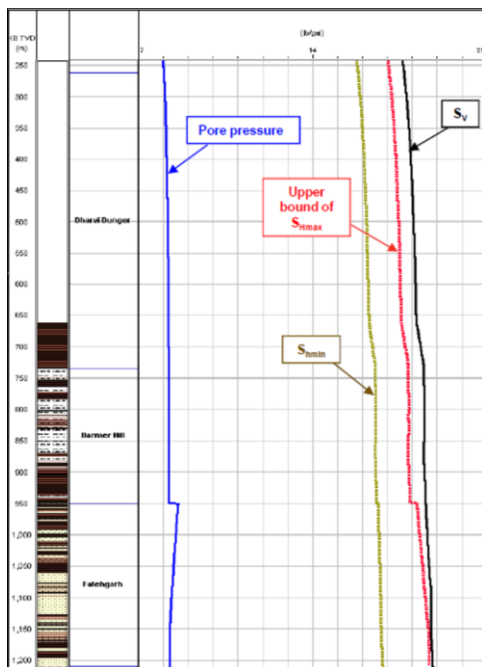


Figure 7: Composite plot of the stress profile and geomechanical model in one of the wells. S_v = vertical stress; S_{Hmin} = minimum horizontal stress; S_{Hmax} = maximum horizontal stress.

Maximum horizontal stress and vertical stress will guide the hydraulic fracture propagation. The integration of minimum horizontal stress magnitude and direction will optimize the placement of horizontal wells in Barmer Hill Formation.

Seismic Attributes

Spatial extent and distribution of reservoir properties can be obtained by integration of seismic data with

geomechanical and petrophysical work. In order to obtain the desired results, post stack inversion methodology was followed. Good quality sonic log (compressional and shear) data was available for the quantitative seismic inversion studies. Well based feasibility study revealed significant contrast between the reservoir and non-reservoir layers. Multiple cross-plots of elastic properties classified the poro-elastic behavior of each unit. Subsequent rock physics modeling suggested acoustic impedance as an effective lithology discriminator (Figure 8). The difference is primarily due to density. The low AI cutoff (as shown in Figure 8) can separate the reservoir from non-reservoirs in different wells (figure 9)

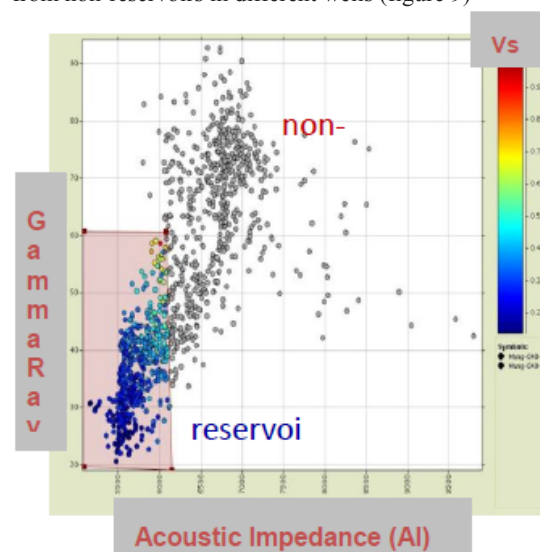


Figure 8: Plot of gamma ray and AI, AI is able to effectively discriminate the lithology (highlighted for reservoir).

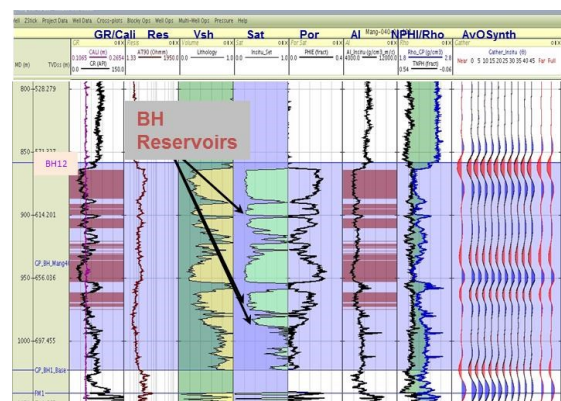


Figure 9: the reservoir zone is highlighted on logs by brown color that corresponds to the reservoir zone in Figure 8.

Post-stack inversion of high density 3D seismic helped to discriminate lithology and delineate its extent as well as

lateral heterogeneity of the reservoir. Seismic attributes were further used for property modeling and identify good areas for hydraulic fracturing as shown in Figure 10.

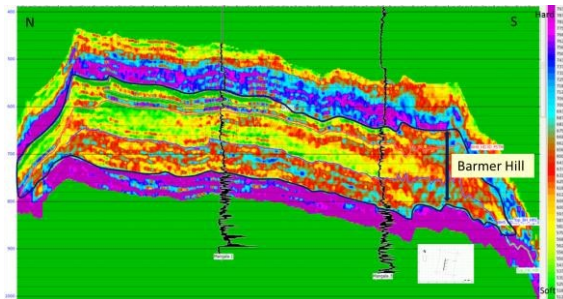


Figure 10: N-S line of P-Impedance volume. Low impedance (green) clearly stands out as better reservoir units.

Conclusion

The value of seismic data to define rock property in tight reservoir is to improve understanding of reservoir quality, completion quality mapping and to guide decisions for wellbore placement. The quantitative relationship between core, log and seismic measurements allowed population of the seismic model with complex properties. The result is a geomechanical model with rock properties that characterize the behavior of each of the units. By defining the variability of groups of properties representing reservoir quality and completion quality across the seismic cube, maps were generated and used as information to define reservoir potential and landing points.

The present work is an integrated workflow for tight reservoir characterization incorporating geological, rockphysical and petrophysical modeling. This workflow will improve understanding of the reservoir properties and continuous mapping along and away from wellbore. This study can be used for optimizing hydraulic fracture design and completion quality of Barmer Hill reservoirs. It can also be adopted for exploitation of other low permeability reservoirs.

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