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Characterization of Shale Plays: A Multidimensional Approach

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Abstract

Due to increasing global demand for clean hydrocarbons, the E&P companies are in search of unconventional resources. One of the unconventional resources is shale gas and shale oil. They have very specific characteristics with lateral and vertical heterogeneity in terms of reservoir characteristics, geochemical and geomechanical properties. Successful drilling in any shale play is dependent on finding the most prospective areas, or the "sweet spots," and aligning the wellbore for maximum borehole exposure to these zones. In shale reservoirs this means placing the well in the most hydrocarbon bearing and brittle zones. This requires a thorough understanding of the shale gas reservoir characteristics. These characteristics require detailed and innovative characterization technologies.

Subsurface parameters like natural fracture, hydrocarbon in place, organic richness and brittleness are the most important parameters that drive the well productivity. This paper illustrates various methods to characterize the shale gas reservoir in terms of the above said subsurface drivers. We have illustrated different approaches to map the sweet spot with data availability and better understanding of the reservoir.

Approch-1: using 3D seismic only
Approach-2: when 3D seismic data and few pilot wells are available
Approach -3: with raw wireline logs of multiple pilots and production data
Approach-4: using multi mineral processed pilot information and production data

In this paper, various seismic attributes of Eagle Ford Shale (i.e. geometrical and simultaneous inversion) are integrated with the normalized production data to map the sweet spots. Apart from this, lateral and vertical sweet spots are identified using raw wireline logs and processed wireline logs through statistical analysis and facies modeling. This paper will help in understanding the subsurface parameters that control the shale play productivity and will guide any operator in Indian landscape to maximize its return by prioritizing the best areas for faster development.

Introduction

Production of gas from shales is not new, although development on a large scale is relatively recent. Twenty years back the trend was slow but in last five years with the technical advancement and enhanced understanding of the shale as a potential reservoir, there is phenomenal growth exploiting the huge resources from these shale plays. Shale gas is the fastest growing energy sector in onshore USA, and interest is rapidly spreading around rest of the world. Successful exploitation of shale gas demands a thorough understanding of the reservoir heterogeneity and its effect on well performance. It is critical to identify the important subsurface drivers and the most productive zones with best reservoir quality. Shale play sweet spots are typically characterized by medium to high Kerogen content, lower clay volumes, higher effective porosity, low water saturation, natural fracture, high Young's Modulus and low Poisson's Ratio. Using these properties as a guide, the geologist and engineers can plan successful wells to unlock the hidden potential of a shale gas play. However, assessment of all the above subsurface parameters requires lot of data. This paper illustrates different approaches to identify the best area i.e. sweet spot where the chances of completing a successful well and maximizing returns are very high. We have described four different approaches with suitable examples from North American shale plays.

Approch-1: using 3D seismic only:

Most of the time we may not get an appropriate well log or log curve to carry out a proper meaningful evaluation of an unconventional shale reservoir. But if 3D seismic data is available in the block, then how can we identify a better area within a block or offered acreage is being explained in this section. As we know natural fracture system very often increases the storage capacity, enhances the permeability and improves efficiency of simulation, so it has a positive impact on the well productivity (Gale et al, 2007). Areas with moderate natural fractures may be the sweet spots and can be identified on 3D seismic data through coherency and curvature attributes.

Fracture prediction using 3D seismic data is generally undertaken using seismic attributes such as curvature and different types of coherence (Hunt et al., 2010). Recent studies have investigated whether curvature attributes can provide an accurate and reliable prediction for fracture distributions and orientation, as well as permitting the definition of subtle faulting and fracturing patterns below seismic resolution (Hakami et al., 2004; Chopra and Marfurt, 2007).

Coherency and curvature volumes are integrated with production log, mud log, borehole image log and chemical tracer of Well-1. It is observed that the zone with less coherency and higher positive curvature corresponds to a zone with higher natural fracture density as indicated by the borehole image log. Chemical tracer and production log data indicates that the maximum hydrocarbon contribution is coming from this fractured zone (Figure-1 & 2).

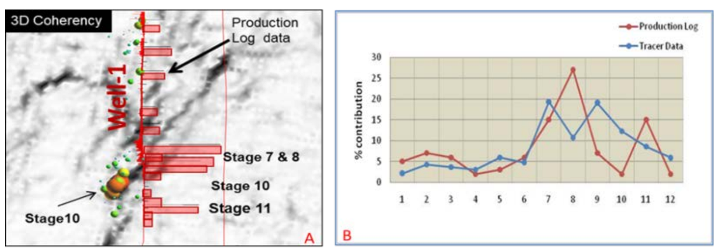


Figure-1: 3D seismic coherency showing fault associated fractures in stage 7-8 and maximum hydrocarbon contribution from the fractured zone as indicated by Tracer and production logs. (Basu et al, 2012, AAPG).

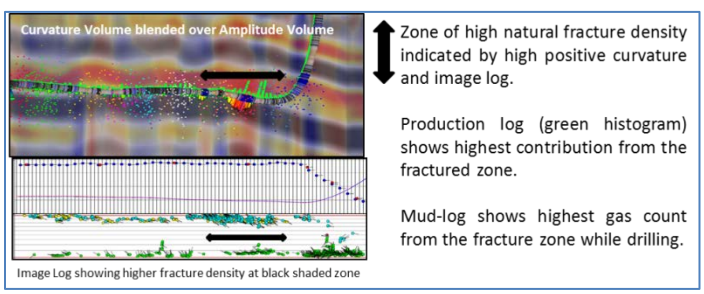


Figure-2: 3D seismic curvature volume integrated with mud log, production log and image log; Maximum hydrocarbon contribution/count is coming from the zone with higher fracture density. (Basu et al, 2012, AAPG).

Approach-2; when 3D seismic data and few pilot wells are available:

With due course of time, few pilot wells get drilled and more point information in form of wire line log becomes available. In this scenario, with the presence of 3D seismic data and few pilot wells information, seismic inversion of pre-stack seismic data can be carried out to improve the understanding of shale gas heterogeneity. Seismic gathers are partially stacked into three equal angle stacks from 0–45° (i.e., 15° angle bands) and simultaneously inverted using multi wells wavelets extracted from each angle stack. Ultra low-frequency model was constructed using interval velocity which does not have reliable information beyond 1 Hz. Remaining (2-15 Hz) low frequency model has been generated from well properties. The standard AVO inversion workflow inverts directly for acoustic impedance (*Ip*), shear impedance (*Is*), and density (ρ). For interpretation purpose these properties are transformed in terms of LMR using the following definitions: Lambda Rho = $Ip^2 - 2\,Is^2$ and $\mu\rho = Is^2$.

In physical terms, lambda is a measure of incompressibility and mu is a measure of shear rigidity. Good way et al. (2010) developed LMR interpretation templates for shale gas using rock physics trends. These templates combined with log, production data and drilling and completion parameters allow seismic inversion data to predict changes in reservoir properties such as porosity, lithology, and stiffness (or "frackability"). Production data were used to support the claim that decrease in LR provide a first-order estimate of sweet spot locations (e.g., Figure 3). Mapping areas of low Lambda Rho, High Mu Rho, low Vp/Vs, and low Poisson ratio are indicative of better reservoir.

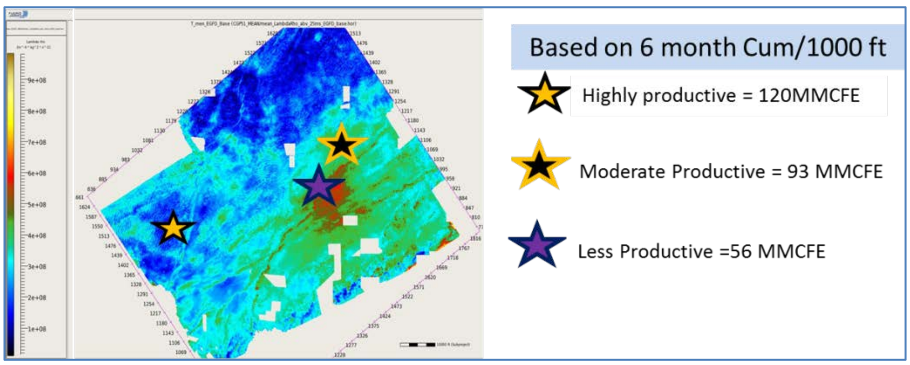
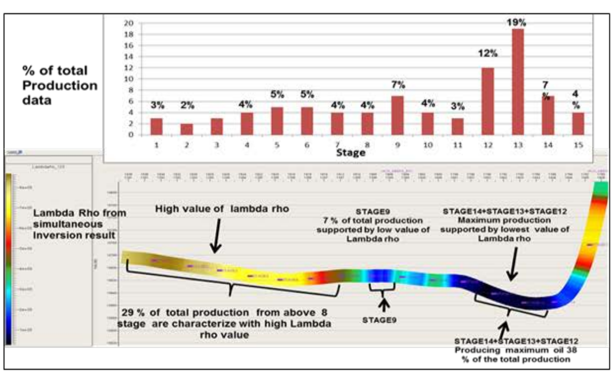


Figure-3: Lambda Rho Map from AVO Inversion correlating well performance.

These geo-mechanical rock properties are very well correlated with stage wise production of well data along the well trajectories as depicted in Figure 4, 5 &6. Geo-mechanical attributes (Lambda rho mu rho and Vp/Vs) in Figure 4, 5 &6 shows stage wise production as recorded in the production log. 38% of total production came from Stage 14, 13 and 12, which are well characterizing from lowest Lambda rho, highest Mu rho and lowest Vp/Vs attributes. The remaining production was recovered from Stage 1 to Stage11 and Stage 15 which shows high Lamda Rho, low Mu Rho and High Vp/Vs. This kind of relationship can guide in selecting the best completion intervals.



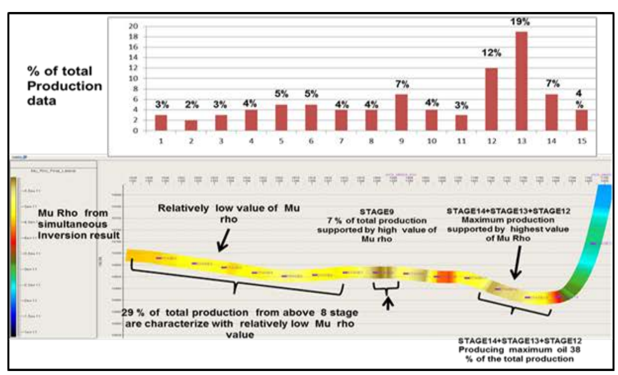


Figure 4: Stage-wise production integrated with Lambda Rho shows an inverse relation; Lower Lambda Rho corresponds to higher production. Figure-5: Stage-wise production integrated with Mu Rho shows a direct relation; higher Mu Rho corresponds to higher production.

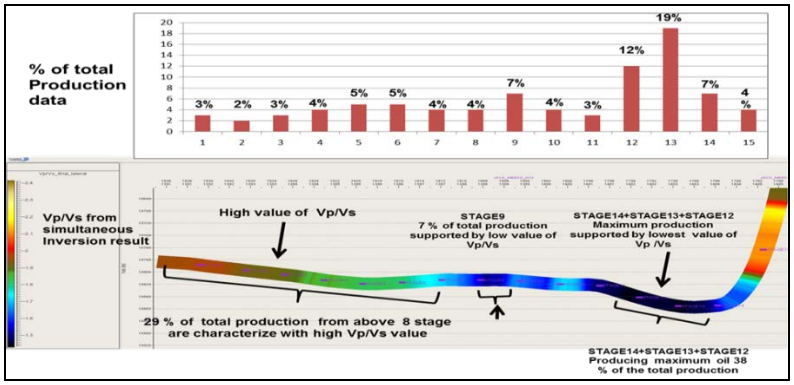


Figure 6: Stage-wise production integrated with Vp/Vs shows an inverse relation; Lower Vp/Vs corresponds to higher production.

Approach-3; with raw wireline logs of multiple pilots and production data:

This is a scenario with several pilot wells information, fair number of producing wells, but no core data to build a robust petrophysical model in order to properly characterize a shale reservoir. In this case to understand the subsurface drivers and to optimize the development strategy, the raw log curves can be integrated with the production data after adequate normalization of both the data set.

In this study we have integrated the normalized production data of around 140 wells with all kind of raw and calculated log curves. Deep resistivity (RT), Young's Modulus (YM) and bulk density (RHOB) are found to have good relation with the well performance (Figure-7). These three parameters indicate hydrocarbon saturation, fracability and organic richness of the shale reservoir respectively. Based on these relationships, certain values of RT (>30 ohm.m), YM (>4.2 MMPSI) and bulk density (< 2.49 gm/cc) represents better performing wells (Figure-7). So sweet spot can be mapped laterally based on these relationships. The areas having resistivity more than 30 ohm.m, Young's Modulus more than 4.2 MMPSI and bulk density less than 2.49 gm/cc can be marked as the best areas (sweet spots) within a shale reservoir.

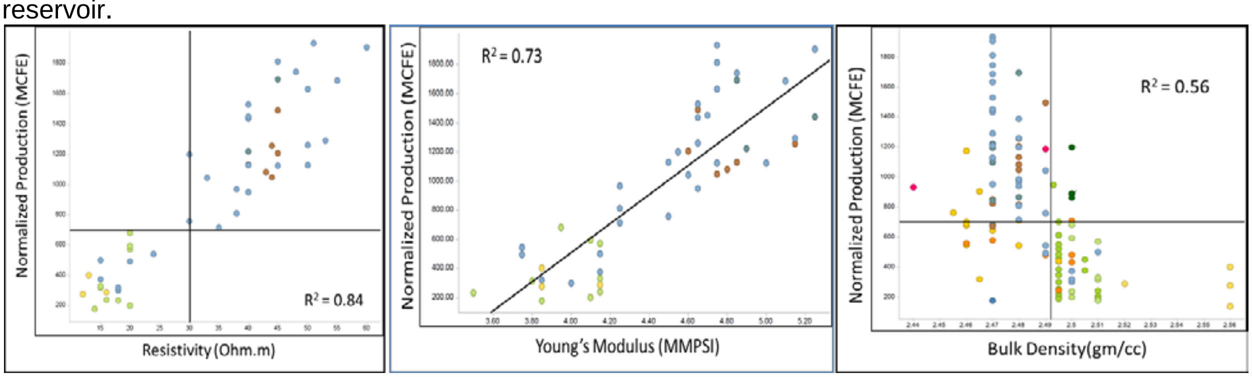


Figure-7 Cross-plots between wireline signature and normalized production. RT (>30 ohm.m), YM (>4.2MMPSI) and bulk density (< 2.49 gm/cc) represents better performing wells.

Net Pay zones are generated in the pilot wells with the above RT, YM and RHOB cut values (Figure-8). The pay thicknesses in the pilot wells are observed to have good correlation with their production. The pay information can also be used to identify the best lateral landing point to enhance the well performance.

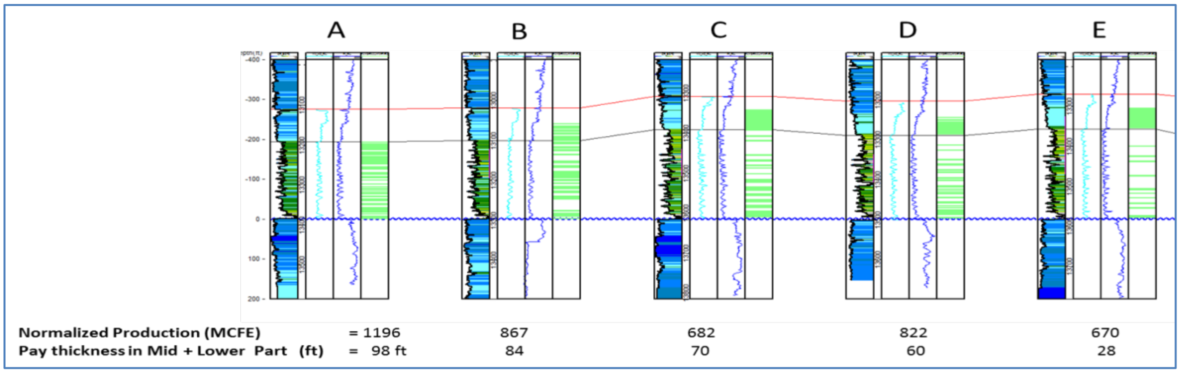


Figure-8: Pay thickness with RT (>30 ohm.m), YM (>4.2MMPSI) and bulk density (< 2.49 gm/cc)

Approach-4; using multi mineral processed pilot information and production data:

This is a scenario when the raw wireline logs of several pilots get converted to actual reservoir parameters like porosity, water saturation, TOC, mineral volume etc. through multimineral processing by an experienced petrophysicist. After achieving the actual reservoir parameters, advance characterization of the shale reservoirs can be carried out to understand the minute variations or heterogeneity. In this study we had an integrated study where production data of several wells, core data of 36 wells and multi-min processed wire line logs of 74 wells are used for shale lithofacies analysis. Initially lithofacies are identified on core data and then it is calibrated to multimineral processed logs using Ternary diagram (Figure-9). The shale reservoir is classified into eight different lithofacies based on three important parameters i.e. mineralogy, TOC and hydrocarbon filled porosity. (Sahoo et al, 2013)

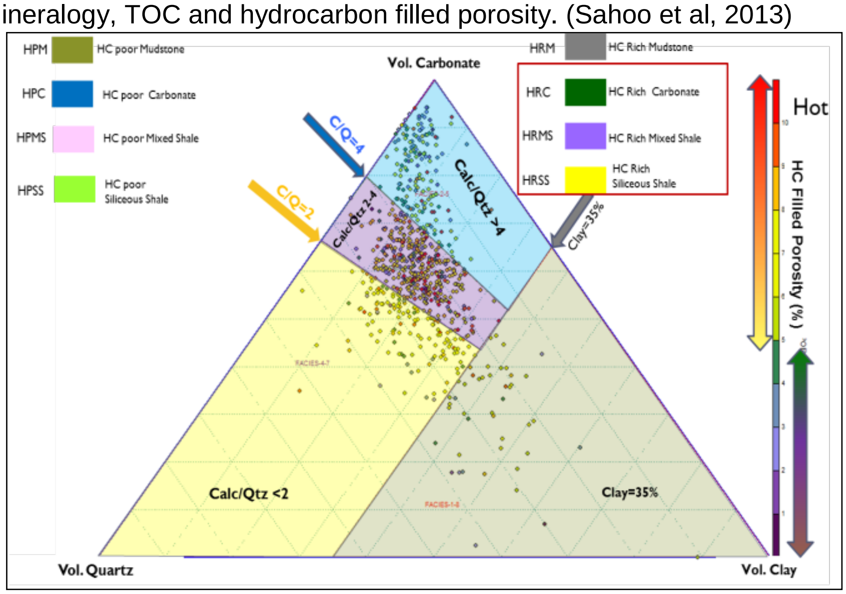
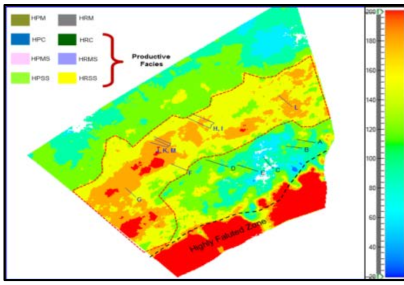


Figure 9: Ternary plot showing the eight lithofacies distribution based on mineral composition and hydrocarbon richness. HRC, HRMS and HRSS are identified as productive facies. (Sahoo et al, 2013)

Then a 3D lithofacies model is constructed by following the same logic and using seismic data, well logs, P-impedance volume etc. To validate the lithofacies modeling, the thickness of three productive lithofacies (i.e. HRSS, HRMS & HRC) are summed up for the lower and middle part of the formation as most of the horizontal wells are placed in that section, and then correlated with the normalized 180 days production data in the pilot wells. A good correlation is observed between the sum thickness of the productive lithofacies and production data (Figure-10).



WELL NAME	Perforated Length (ft)	180 Days Production/ ft (Mcfe)
A	5376	96.44
B	5150	101.69
C	5293	146.41
D	4398	178.52
E	4757	147.03
F	5850	211.79
G	4242	331.03
H	5707	287.18
I	5706	319.00
J	4414	294.30
K	4261	324.53
L	3312	308.91
M	4243	325.78

Blue Wells: Good Production
Black Wells: Less Production

Figure-10: Productive Facies Map (sum thickness of 3 productive facies) in the lower and middle part of the shale formation derived from the facies model with integration of production data. (Sahoo et al, 2014).

Summary:

Shale Play characterization is very important and is mainly data driven. With the maximum utilization of the available data how the sweet spot can be identified through proper characterization of the shale reservoir has been illustrated in this analysis. Four different approaches were described to understand the shale reservoir response to the well performance.

It has been observed that 3D seismic data can help in identifying the sweet spots through high natural fracture density, low Lambda rho, high mu rho, low Vp/Vs in terms of brittleness. Availability of several pilot well information, production data and robust petrophysical model help in identifying sweet spots through raw log integration and facies modeling.

With the onset of shale gas revolution in Indian Landscape any operator may follow the above four approaches depending on the data availability to optimize the field development in order to maximize the return.

Acknowledgments:

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