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Comprehensive Petrophysical & Geomechanical Analysis to Identify Unconventional Shale Reservoirs and their Fracability in Selected Wells of North Cambay Basin - A case study

Abstract

The quest for unconventional reservoirs in recent times has provided a boost to shale gas/oil prospects in Indian basins. After encouraging results from the wells exclusively drilled for shale exploration in South Cambay Basin, COD – Shale Exploration drilled dual objective wells in various fields of North Cambay Basin. The main objective of this study is to identify unconventional shale reservoirs in Cambay Shale/ Olpad section and their fracability in these wells. In this case study, five of these wells have been analyzed for petrophysical and geomechanical aspects.

Comprehensive analysis of petrophysical data along with available geochemical data has brought out intervals those are organic rich and are having good thermal maturity. TOC was calculated from logs using customized formula developed at CEWELL and was compared with lab derived TOC data to find its efficacy and for use in further processing. Kerogen volume and hence TOC log was also generated for studied wells through NMR-ECS (wherever available) & Density log combination. A multi-mineral processing model based on conventional & advanced log data and results of lab studies on cores was built to estimate porosity, fluid saturation and volume of minerals. Petrophysical interpretation was calibrated with the available core data to arrive at the core integrated Petrophysical interpretation.

Knowledge of Shmin magnitude (fracture gradient) and its orientation along with many other parameters is desirable for designing a successful hydro-fracturing job. Log based 1-D Geomechanical Models of these wells comprising of overburden, pore pressure, fracture pressure, rock compressive strength, rock elastic properties, horizontal stresses, brittleness and stress barriers have been prepared on Techlog platform and calibrated with the available geological, rock mechanical and drilling data. TVI studies were carried out for estimation of Transverse Vertical Isotropy in one well, in which Sonic Scanner data was available. Best suitable zones for H/F job were selected through comparative analysis of various identified zones in respect of their hydrocarbon potential, reservoir quality & fracability.

Introduction

All the five studied wells are from different fields of north cambay basin, which fall in Ahmedabad - Mehsana block (Fig.1). The formations considered for this study are Younger Cambay Shale, Older Cambay Shale and Olpad formations. These are of Palaeocene-Eocene age.

Cambay shale is deposited in lower deltaic (marginal marine environment) which are often marked by abundance of sub-environments which result in complex stratigraphic stacking. Consistent to the depositional environment and the source of sediments, the mineralogy is complex and lateral variation of reservoirs properties may be expected. Since these wells are dual objective wells, many advanced logs were available. Also, extensive geochemical studies were carried out on conventional core, sidewall cores and cutting samples. Triaxial lab data was also available in two wells. All of this data was integrated and a holistic approach was adopted to arrive at any co

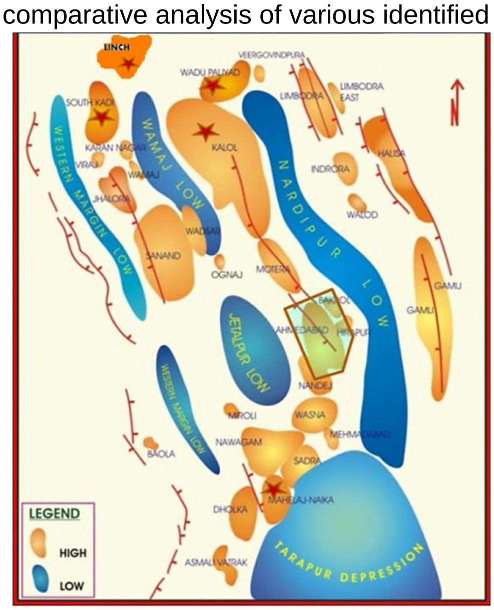

Fig.1. Map of the study area

Methodology

Construction of processing model:

X-ray diffraction studies carried out on core samples in the study area reveals the presence of kaolinite and chlorite as dominant clay minerals and also limited amount of siderite & pyrite at places along with quartz. Since we are dealing with Cambay shale which is a potential source rock, as indicated by higher TOC values (>2wt %), kerogen is also present which has similar effect as porosity on all porosity logs. In order to evaluate such complex and varying shale reservoir, mineral set considered in processing model comprises of quartz, kaolinite, chlorite, siderite, pyrite & coal. Carbonaceous matter is taken into consideration, wherever observed. A special mineral is also included in the model to incorporate the effect of kerogen volume.

Oil has been taken along with water as fluids considering the maturity window for Cambay shale of North Cambay basin. To accommodate so many minerals in processing model, help has been taken from advanced logs. The equation channels selected are: Si, Fe, Al & Ca elemental channels of ECS, 3ms & total porosity of CMR, Th & U of NGS and TOC log (for kerogen) in addition to conventional logs GR, RHOB, NPHI, DT, Rt, & Rxo. Processing has been carried out using dual water saturation equation.

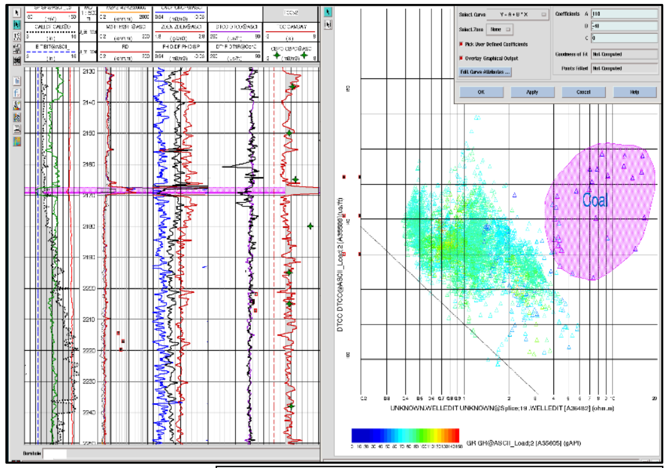

Fig.2. TOC estimation in well E

Estimation of depth-wise TOC:

CEWELL Method: Following the concept of modified Passey method, a new technique has been developed recently at CEWELL for authentic and quantitative estimation of depth-wise TOC values (TOC Log) from conventional logs. This has widespread applications and removes shortcomings of Passey method which is presently in vogue.

TOC (wt%) = { LogR – (b – Dt) /m } x 10 (2.297 – 0.1688 x LOM)

A baseline through low resistivity and low sonic points is plotted on a semi log z-plot of deep resistivity, sonic log and gamma ray. ‘b’ is the intercept and ‘m’ is the slope of this base line. R and Dt are log value of Resistivity & Sonic at desired depth (Fig.2). LOM is defined as Level of Organic Metamorphism - a measure of thermal maturity. Hoods et al. established a relationship between VR (vitrinite reflectance) and LOM (Fig.3). In North Cambay Basin, LOM (thermal level of maturity) has been considered to be 10 for YCS and 10.5 for OCS.

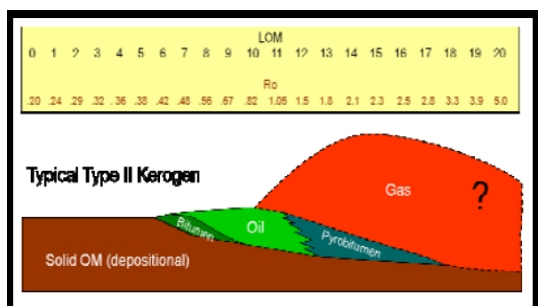

Fig.3. Hood’s chart for LOM

CMR-ECS-Density Log Combination Method: Density log sees a kerogen-rich zone as porous, whereas the kerogen will appear as matrix to a CMR log. Based on this, the difference in these two volumes can be equated to Kerogen volume.

$$V_{ker} = \Phi_{density} - \Phi_{cmr}$$

$$TOC\ (wt\ \%) = V_{ker} * \rho_{ker} / \rho_b * k$$

Where, ρ_{ker}= Kerogen density (gm/cc), ρ_b= bulk density (gm/cc), & k = kerogen conversion factor. TOC does not account for other elements that may occur within kerogen (H, O, N, S). So, a conversion factor (*k*) is required that accounts for the missing elements and considers Kerogen type & maturity. The conversion factor is considered 1.2 in the present study.

Estimation of Hydrocarbon Prospects through multi-mineral processing of log data:

CMR log shows free fluid porosity (with 33msec cut off) is almost negligible and 3mse sity is significantly high (8-12%) at many places and unexpectedly high at some places (more than 15%) against Cambay shale. SRP (shale rock properties) studies carried out on core samples at different depth points by Weatherford show that dry helium porosity varies between 10.3-22.5%. In view of above, to accommodate CMR data into multi-mineral processing model, 3ms CMR porosity channel has been used as free fluid porosity equation in the model along with usual TCMR (total CMR porosity) channel for total porosity. This is virtually equivalent to lowering T2 cut off to 3ms level to evaluate such unconventional reservoir having very small pores.

Validation and presentation of Processed Data:

For validation, grain density obtained from volumetric analysis has been compared with ECS grain density and effective porosity (PIGN) with CMR 3msec porosity. A very good fit is seen in both the cases (Fig.4). Also, derived total porosity (PHIT) is seen to have excellent match with helium dry porosity obtained from SRP studies carried out on core samples.

Overburden/ Vertical Stress Estimation:

The vertical component of the overburden stress at depth, z, is calculated by integrating the weight above the point z using the following equation,

$$S_V=\int_0^z \rho g \, dz$$

Fig.4. Processed data for well A

Wherever necessary, a pseudo-density profile was created from acoustic data using the Gardner equation:

$$\rho = A\left(\frac{10^6}{DT}\right)^B$$

A = coefficient (0.22 in this project all lithology)
B = exponent (0.26 in this project all lithology)

The density data was integrated with the respective density trend to obtain a continuous vertical stress (overburden) profile for each well. For QC, density from RHOZ and Gardner were matched in the top interval of RHOZ.

Pore pressure Estimation:

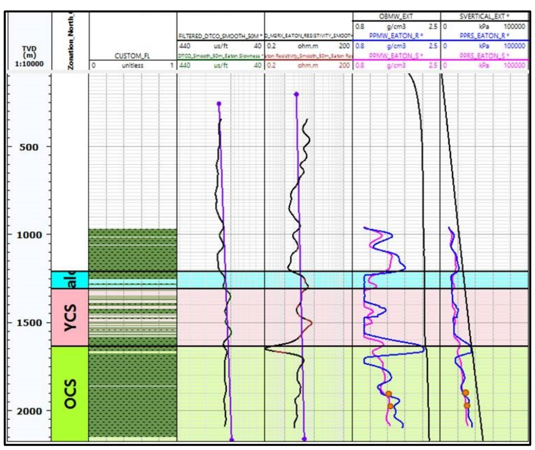

Fig.5. Pore pressure estimation in well C

Apart from direct measurements from well test/MDT tests, pore pressure can be estimated using several log based methods (Eaton's, Bower's and Miller's etc.), each typically relating velocity and/or resistivity to the pressure signal in the formation due to under-compaction. In this study **Eaton's trend line method** has been used, wherein deviation of porosities from a normal compaction trend for the field is seen.

$$P_P = \sigma_v - (\sigma_v - P_{Pnorm}) \times a \times \left(\frac{DT}{DT_{norm}}\right)^n$$

In semi-log trend line: $\log(DT_{norm}) = DT_0 + KZ$

Where, Z is the depth measured from the mudline, DT is the measurement value, DT_0 is the measurement of sediments at the mudline, DT_{norm} is the measurement value if the formation was normally pressured, PP_{norm} is the normal pore pressure, a and n are fitting parameters named Eaton factor and Eaton exponent respectively. The values used for Eaton's method using sonic log are: a=1 and n=3.

Similar expression as above can be used for the resistivity derived pore pressure. The value of n used in this case is taken as 1.2. However, due to large variation in the values and excessive spikiness in resistivity logs, sonic log data was considered in final pore pressure prediction (Fig.5).

Hoseni curve (density-velocity cross-plot) differentiates between different mechanisms of overpressure generation. It was prepared for YCS & OCS separately for all the five studied wells and

Normal/Disequilibrium compaction was found out the most common mechanism encountered in case of these wells (Fig.6).

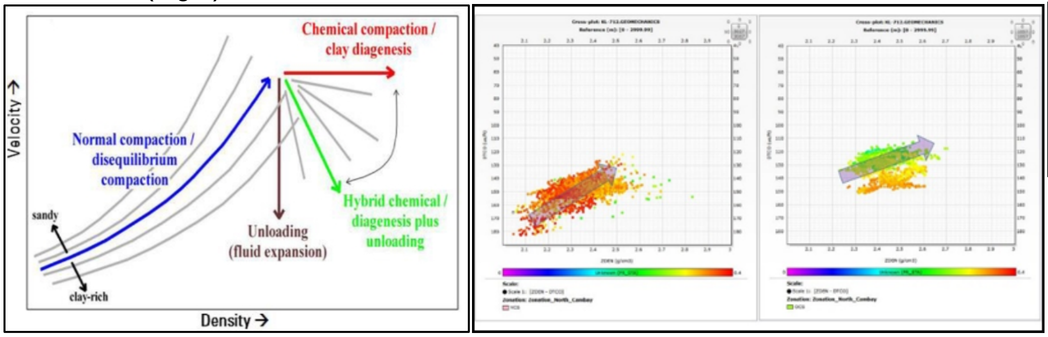

Fig.6. Hoseni plots prepared in well A

Rock Elastic Properties and Rock Strength:

Since we are assuming the rock to be elastic, we need any two static elastic properties to define it mechanically. In this study Static Young's modulus and Static Poisson's ratio have been taken. These log derived static values of Static Young's modulus and Static Poisson's ratio are fairly matching with the values estimated through triaxial rock tests carried out in wells B and C, which corroborate the efficacy of the correlations adopted.

$\ln E_{static} = 14.9 - 0.61*\ln(DTCO) - 2.18*\ln(DTSM) + 1.42*\ln(RHOB)$

$PR_{sta} = 0.8*PR_{dyn}$

$$UCS = 0.77*\left(\frac{304.8}{DTCO}\right)^{2.93}$$

Tensile Strength= 0.1 * UCS

Friction Angle: In this study, clay volume and porosity correlation developed by Dick Plumb was used to derive Friction angle.

Cohesion: $$COH = \frac{UCS}{2\left[\sqrt{(1+(\tan FANG)^2} + \tan FANG\right]}$$

Stress magnitude estimation:

In this study, a poro-elastic horizontal strain model (Fjaer et al., 1992) is used to estimate the magnitudes of the minimum and maximum horizontal stresses. The two strains εx (in the minimum horizontal stress direction) and εy (in the maximum horizontal stress direction) can be used as calibration factors to match the stress model to the current state of stress in the subsurface. From this approach, we obtain

$$\sigma_h = \frac{\nu}{1-\nu}\sigma_v - \frac{\nu}{1-\nu}\alpha P_p + \alpha P_p + \frac{E}{1-\nu^2}\epsilon_x + \frac{\nu E}{1-\nu^2}\epsilon_y$$

$$\sigma_H = \frac{\nu}{1-\nu}\sigma_v - \frac{\nu}{1-\nu}\alpha P_p + \alpha P_p + \frac{E}{1-\nu^2}\epsilon_y + \frac{\nu E}{1-\nu^2}\epsilon_x$$

Calibration of the Maximum and Minimum Horizontal Stress Magnitude:

Magnitude of Shmin can be calibrated by Leak off tests or mini fracs. SHmax magnitude has to be estimated indirectly. Hottman, Smith et al. (1979) used variations of the occurrence of breakouts (as indicated by wellbore spalling) and drilling induced tensile fractures with changes in mud weight to make an estimate of the maximum horizontal stress, after first constraining the other parameters associated with wellbore failure.

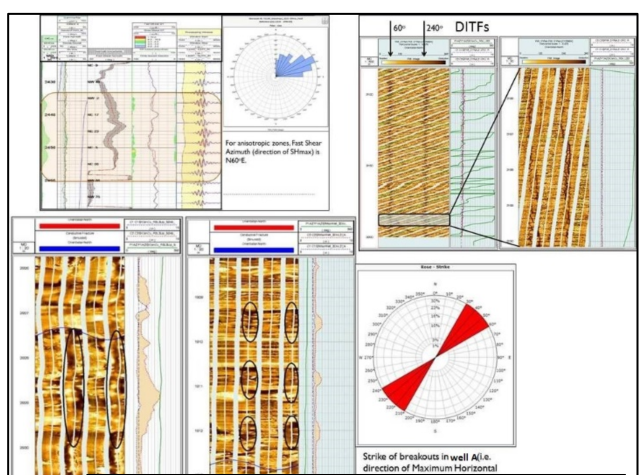

Fig.7. Stress direction estimation in well A

Direction of Horizontal Stresses: In cases of stress related anisotropy if the rock is not drilled with appropriate mud weight, breakouts starts appearing in the direction of Shmin and drilling induced fractures in the direction of SHmax. Also, fast shear azimuth in anisotropic zones gives SHmax direction. Considering all the available data, direction of Maximum horizontal stress S_{Hmax} is 60/240 deg and direction of Minimum horizontal stress S_{hmin} is 150/330deg (Fig.7).

Wellbore stability analysis and 1D Geomechanical Model Calibration: The best way to calibrate a 1-D MEM is to verify the predictability of the model. Using the computed rock properties and horizontal stresses, wellbore stability analysis tells us how good the MEM is by comparing the predicted wellbore stability with the drilling events observations, breakouts or drilling induced tensile fractures observed on image or caliper logs. Generally, the model can be verified against these compressive and tensile failure occurrences as observed in image logs or caliper logs, if coverage is good. Fig.8 is final wellbore stability template for well A. Entire 12.25” section is highly caved as shown by caliper log. Interval 2250-2350m shows the occurrence of breakouts in the model which are also showing their presence on recorded FMI log. Similarly, in the bottom interval 2750-3000m, presence of breakouts is corroborated on FMI log. It is observed that among modeled stresses, Shmin is least is magnitude and Vertical stress Sv is the greatest. This shows that this is predominantly a normal faulting regime. However, in Olpad section, SHmax has reached a value almost equal to Sv, which indicates this section to be in an intermediate faulting regime between normal faulting and strike slip.

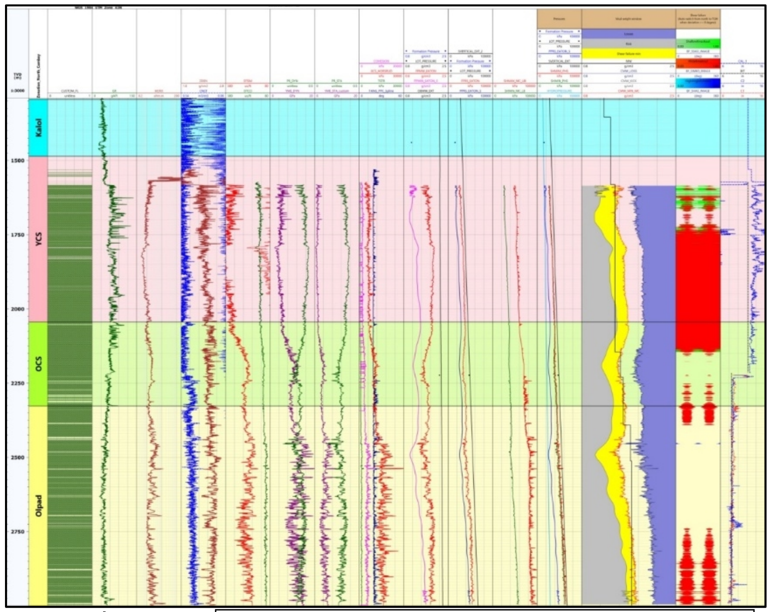

Fig.8. Wellbore Stability Analysis in well A

Estimation of Brittleness Index:

BI = (En+vn) /2

Where, En and vn are normalized Young’s modulus and Poisson’s ratio, and are defined as follows:

En = (E-Emin) / (Emax-Emin) and

vn = (vmax-v) / (vmax-vmin)

In simple terms, a brittle rock has relatively higher Young’s modulus and a relatively lower Poisson’s ratio. For all the studied wells, YME-PR cross-plots were prepared and interacted with the recommended prospective zones (Fig.9).

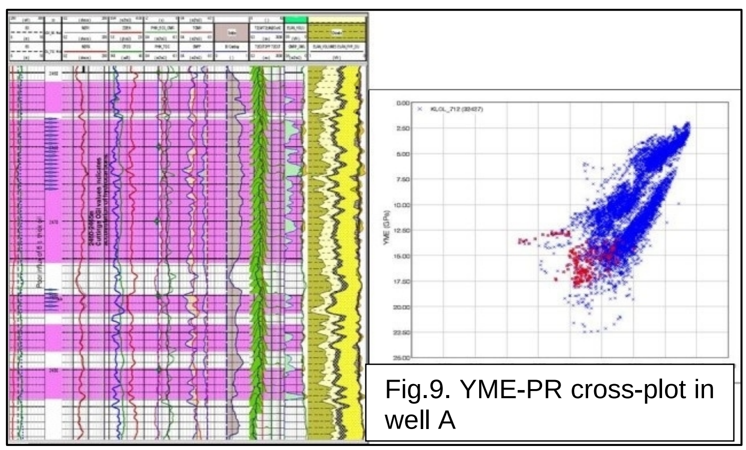

Fig.9. YME-PR cross-plot in well A

Anisotropic Stress Modeling of Shale: Well A has got sonic scanner data in the zone of interest and this data has been processed for TIV anisotropy. All stiffness tensor components have been estimated and the values of Young’s modulus and Poisson’s ratio have been computed in the horizontal and vertical planes. This is shown in Fig.10 (left). If we consider the anisotropic model of stresses, the expression of minimum horizontal stress looks as:

$$\sigma_h - \alpha\sigma_{pp} = \frac{E_{horz}}{E_{vert}} \frac{v_{vert}}{1 - v_{horz}} (\sigma_v - \alpha(1-\xi)\sigma_{pp})$$

We have estimated the minimum horizontal stress in both the scenario, i.e. one with isotropic consideration and another with TIV anisotropy, and compared both of them in Fig.10 (right). It may be noted that above 2430m, which is pure thick shale, there is a significant difference between these two stresses. This is because of large TIV anisotropy in shales due to its internal structure, as already discussed. However, the difference in stress is not very significant in the section below 2430m, possibly because of presence of considerable amount of sand and silt. Thus it may be concluded that TIV consequences become all the more important when clay amount increases in the reservoir.

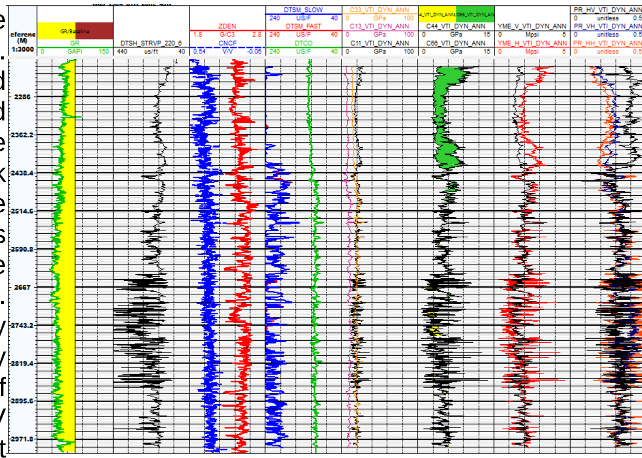

Fig.10. Stiffness tensor coefficients and vertical/horizontal YM and PR (left), isotropic and anisotropic fracture gradient comparison (right)

Petrophysically prospective zones were analyzed for their fracture pressure, brittleness and fracture barriers as discussed above and best suitable candidates were recommended for hydro-fracturing.

Conclusions:

- Although the five wells under study are from different fields, the general TOC range observed in OCS is from 2.5 to 4. The log estimations of TOC are in good match with the lab generated data. The maturity starts in OCS in these wells and the VRo value goes up to the maximum of 0.81, which falls in the oil window.
- The Younger and Older Cambay shales are in normal stress regime, while Olpad section falls in intermediate to strike-slip regime.
- Shales are mostly observed to be over-pressured, primarily because of compaction disequilibrium.
- The MEM's have been subjected to well failure predictions in all the studied wells and the predicted failures have been matched with actual failures seen on image logs in these wells for model validation. Good agreement has been observed between these two in all the wells.
- The estimated Static YME and Static PR through different correlations were matched with lab data at these points and they were seen to be in agreement.
- The average maximum horizontal stress orientation is 60/240 deg. This direction will be favorable from hydro-fracturing perspective, as fractures will propagate away from the wellbore.

Acknowledgment

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