Effect of confining pressure on petrophysical constant & acoustic parameters through core samples and its integration with log data: A case study in Sadra area of Cambay Basin

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Keywords

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Abstract

For realistic reservoir characterization in a heterogeneous reservoir, it is crucial to get an accurate estimate of reservoir parameters such as porosity, permeability minerals and fluids along with their volumes. Therefore, mineral compositions, petrophysical constants and acoustic parameters need to be known for K-IX sand of Sadra filed. The study aims to analyze the effect of confining pressure on Tortuosity factor (a) & Cementation factor(m), saturation exponent (n), compressional Wave velocity(Vp), Shear wave Velocity (Vs) on core samples under in-situ pressure condition, integrating open hole log data, mineralogical assemblage in order to address the challenges of inconsistency in production behaviour vis-à-vis log character of K-IX sand of Sadra filed of Cambay Basin.

In general, the petrophysical parameters are determined on core samples under ambient condition. However, overburden pressure influence petro physical parameters and constants significantly. To analyze the effect of in-situ pressure condition a study was carried out on 29 core samples, at varying pressure in stages. It was found that ‘a’ decreased from 1.0 to 0.88 with increase in confining pressure up to 3000 psi. The petro physical constants 'a', 'm' and 'n' changed significantly under in-situ pressure condition in comparison to ambient condition. The porosity values under in-situ pressure condition were approximately 1.32 times smaller in comparison to porosity measured under ambient condition. Water saturation (Sw) increased marginally using lab derived parameters at overburden pressure with respect to conventional ‘a’, ‘m’, and ‘n*’ parameters. Therefore, petro physical constants under in-situ pressure condition are substantially different from ambient condition. It was observed that as the confining pressure increased both Vp and Vs velocities also increased but after 2500 psi pressure change in velocities was very less. The velocities changed with change in pore pressure also (20psi to 260 psi pressure). Also both Vp and Vs correlate linearly with porosity. Relationship were established between Vp and Vs under ambient & in-situ pressure condition. These relationship can be used to predict shear velocity in the wells where it is not recorded.

After analyzing and integrating all the core data with log data, a multi-mineral petrophysical model was standardized for evaluating K-IX pay sand of Sadra field under in-situ pressure condition. The input parameters were selected based on core derived sedimentological, petrophysical and log attributes. Formation evaluation results obtained by using standardized multi-mineral petrophysical model helped to identify and estimate the minerals & fluid volumes accurately in the Sadra field of Cambay Basin.

Introduction

Cambay basin is a narrow, elongated, intra-cratonic rift, situated in the north- western part of Indian Craton, in the state of Gujarat. The basin is one of the major on-land hydrocarbon producing basin across India. The field studied is located on the northern rising flank of Tarapur Depression in the Mehsana-Ahmedabad tectonic block of North Cambay Basin. The K-IX pay sand is a regionally distinct coarsening upward sequences ending with coal developed within the Formation and hydrocarbon accumulations have been established in the reservoir. However, owing to heterogeneous nature of K-IX reservoir, processing and interpretation for fluid saturation and mineral volumes is not easy. Also, there is inconsistency in production behaviour vis-à-vis log character.

Methodology

Petro physical studies on core samples from different well of Cambay basin have been taken up for the study. Total 40 core plugs were taken for the study. First of all core samples were cleaned to remove hydrocarbon, salt and other impurities by soxhlation process using toluene and methanol. Subsequently, all core samples were dried at 60 degree Celsius. Porosity, grain density and bulk density of all core plugs were determined using state-of-art KEYPHI equipment. Plugs were then fully saturated with brine salinity of 200 grams/litre. Resistivity and formation factor of each core sample are measured by the Overburden Resistivity Meter (OBR) instrument under varying pressures. The core plugs were de-saturated by means of a centrifuging at different speed viz 1000, 2000 & 3000rpm. The de-saturated weights and their corresponding resistivity were measured at each stage. To analyse the effect of in-situ pressure condition on porosity a varying pressure of 500 to 3000psi was applied in stages on 13 core samples and the measurements were made.

The ‘a’, ‘m’ and ‘n’ parameters are determined using the values of resistivity and formation factor of individual core plug at ambient and 3000 psi pressure condition.The Limiting Formation Resistivity Factor ‘Flim’ is determined by measuring the resistivity ‘Ro’ of core plugs fully saturated with brine of 200.0 gm/lt salinity. The potential difference across the sample is measured and thus resistance calculated. Once the resistance of the core sample has been determined, its resistivity can be calculated. The resistivity of brine ‘Rw’ is determined from the standard correlation. Limiting formation resistivity factor ‘Flim’ is then calculated using the relation:

$$F_{\lim} = \frac{R_o}{R_w}$$

The Tortuosity factor ‘a’ and Cementation factor ‘m’ are related to ‘Flim’ and ‘ϕ’ by the following equation:

$$F_{\lim} = \frac{a}{\phi^{-m}}$$

The cross-plot on log-log scale between ‘Flim’ and ‘ϕ’ has been used to derive the values of ‘m’ and ‘a’ where the intercept on ‘Flim’ - axis at ϕ = 100% determined the value of Tortuosity factor ‘a’ and the slope of the best fit line determined the cementation exponent ‘m’. The values of resistivity index ‘I’ and corresponding water saturations ‘Sw’ calculated from the above data are plotted on log - log scale. Saturation exponent ‘n*’ has been computed by plot between I and Sw. The relationship between I and Sw is given by: -

$$I = (Sw)-n*$$

Eight core plugs have been prepared for the analysis of acoustic studies. Compressional wave velocity and shear wave velocity are measured by the instrument at varying pressures, under 200 psi, 300 psi, 400 psi, 500 psi, 1500 psi, 2500 psi and 3500 psi pressure conditions. The velocities are calculated with AVS-700 as follows:

$$Vp = Lp / \Delta Tp$$

$$Vs = Ls / \Delta Ts$$

Where V = Pulse propagation velocity in m / sec.
L = Pulse travel distance in centimeters
ΔT = Effective pulse travel time (i.e. measured time minus zero time correction)
Sonic travel time ΔT = 1/V

To identify the clay typing and other mineral contents of the formation, sedimentological core analysis has been carried out on core samples. The petrophysical constants and minerals identified from logs and cores are used to develop a standardized multi-mineral log processing model. The model has kaolinite, chlorite as main clay minerals along with siderite as heavy mineral. Log data of some of the wells have been reprocessed with the standardized model and processed outputs have been validated with initial production testing data and the core derived porosity, permeability and mineralogy.

Results & Analysis

The study aims to analyze the effect of overburden pressure on Tortuosity Constant (a) & Cementation factor(m), saturation exponent (n), compressional Wave velocity(Vp), Shear wave Velocity (Vs), Vp/Vs ratio, poison ratio, rock-mechanical parameters through core samples sandstone reservoir and its impact on reservoir parameters.

Effect of In-situ Pressure on Porosity:

The porosity measurements on 40 core plugs of 1.5″ diameter was carried out using state-of-art Porosimeter-Permeameter (KEYPHI) equipment at ambient condition and a total of 13 core plugs were studied at in-situ pressure condition. The core derived porosity vary from 4.2% to 21.5% at ambient condition whereas it ranges from 2.99% to 16.53% under in-situ pressure condition. The different rock samples followed almost the same trend with confining pressure change.

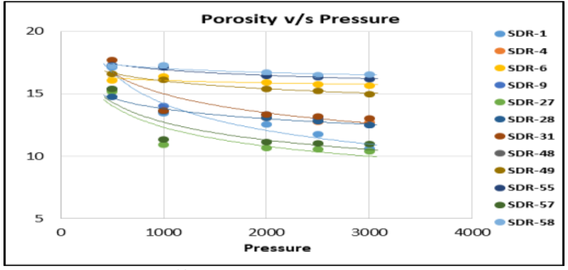


Figure 1: Effect on Porosity with varying pressure

It is observed that the porosity values under in-situ pressure condition are approximately 1.32 times smaller in comparison to porosity measured under ambient condition. (Fig-1)

Effect of overburden pressure on Permeability:

The unsteady-state pressure falloff technique was used to measure permeability with Helium gas for the same core plugs using the Porosimeter-Permeameter (KEYPHY) equipment. Helium injection pressure (pore pressure) was 400 psi while the confining pressure was varied from 500 to 3,000 psi. The permeability values obtained were in the range of 0.016-114.6mD. The permeability values of the core plugs decrease significantly with increase in confining pressure. (Fig-2)

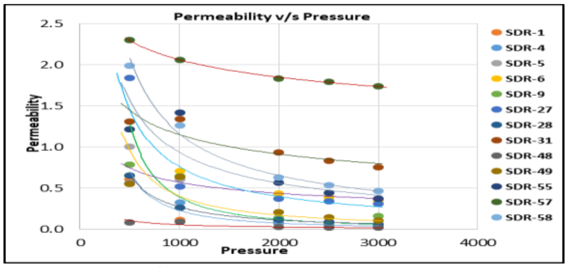


Figure 2: Effect on Permeability with varying pressure

Effect of In-situ Pressure on Petrophysical Constants:

The core derived 'a', 'm', 'n' parameters at ambient and in-situ pressure conditions (Fig 3 & 4) are found to be 1.0, 1.72 & 2.13 and 0.88, 2.26 and 2.41 respectively for K-IX pay sand of Sadra field. However, tortuosity factor ‘a’ decreased from 1.0 to 0.88 with increase in confining pressure up to 3000 psi.

Wyble (1958) in his study also showed that the cementation exponent (m) of one of the samples increased from 1.87 to 2.04 (+9.1%) as a result of increase in pressure up to 5000 psi. He also observed that there is a drastic decrease in permeability with the increase in overburden pressure for sandstones. Therefore, it is evident that petro physical constants under in-situ pressure condition are substantially different in comparison to ambient condition.

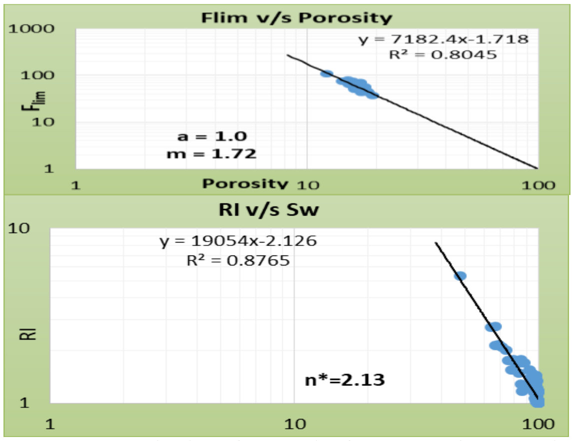


Figure 3: Determination of Tortuosity factor ‘a’ and Cementation Exponent ‘m’ and Saturation exponent ‘n’ at ambient Condition

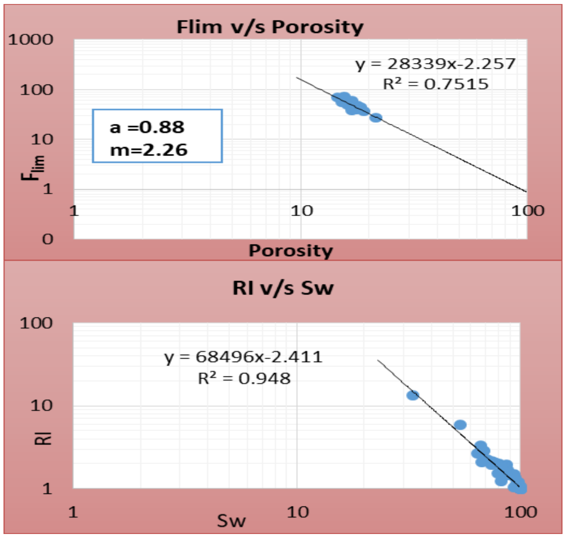


Figure 4: Determination of Tortuosity factor ‘a’ and Cementation Exponent ‘m’ and Saturation exponent ‘n’ at Overburden Condition

Effect of confining pressure on Formation Resistivity Factor:

Resistivity is an important physical property of a reservoir. It describes the ability of the rock samples to conduct electrical current, mostly through the brine within the pores of the core samples. 13 saturated core plugs of diameter 1.5 inch were studied using the four-electrode technique. Changes are observed in the resistivity of saturated core plugs under varying confining pressure condition. These changes are attributed to change in internal pore structure and increase in tortuosity and decrease in the effective cross-sectional area that is available for the flow of electric current. A systematic decrease in rock conductivity and increase in formation factor as the overburden pressure increased over the range of 500 to 3000 psi was also observed. It was also observed that the cementation exponent of the sample studied, increased from 1.72 to 2.26 for the different core plugs studied as a result of increasing the confining pressure up to 3000 psi. However, tortuosity factor ‘a’ decreased from 1.0 to 0.88 with increase in confining pressure up to 3000 psi.

Formation factor and cementation factor increase as the overburden pressure increases to 3000psi. This indicates the overburden pressure reduces the bulk volume as at low overburden pressures, fissures start to close with small compression in mineral grains. As the overburden pressure increases, the rock undergoes bulk compression resulting from pore and grain deformation. Also, as the pressure is depleted in a reservoir, the effective overburden pressure increases causing a reduction in pore volume. These results indicate the rock is compacted as a result of overburden pressure, the matrix is under stress and porosity and permeability decrease, and therefore, the formation factor and cementation exponent would change.

Effect of confining pressure on Acoustic velocity:

The data indicates that the velocities increases as the confining pressure is increases (fig 5) and therefore, the velocities at reservoir confining pressure are more as compared to those at ambient conditions. It is found that as the confining pressure increases (200psi to 3500psi) both Vp and Vs velocities increases with pressure but after 2500 psi pressure change in velocity is very less. Transform between Vp & Vs generated for ambient and in-situ pressure condition which may be used to evaluate shear velocity as where DSI log data is not available.

The relationship established between Vp and Vs for brine saturated core plugs under reservoir and ambient pressure conditions is given by the following equation (Fig-6) are as follows:

$$Vp = 1.6335Vs + 38.061 \text{ at 200 psi}$$
$$Vp = 1.4953Vs + 510.35 \text{ at 3500 psi}$$

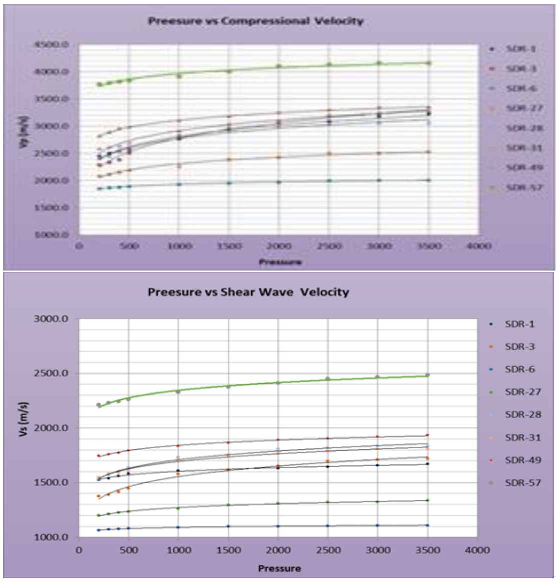


Figure 5. Effect on Compressional and Shear wave velocity with varying pressure

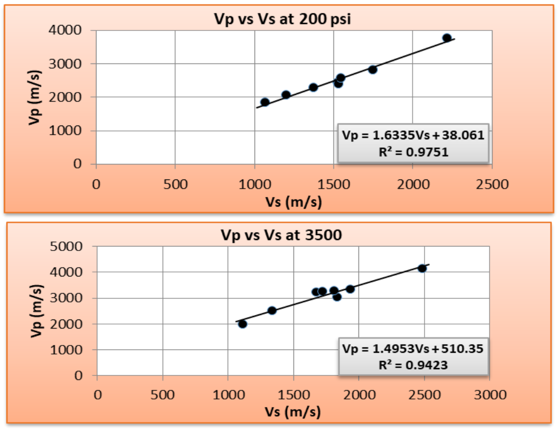


Figure 6. Cross plot between Vp and Vs for K-IX Formation at 200 psi & 3500 psi

Similar relationships have also been established by Costagna et al (1985) and Han et al (1986) with different values of coefficients for water saturated clastic silicate rocks and sandstones respectively.

The velocity changes with change in pore pressure (20psi to 220 psi pressure) also (Fig-7). The velocities have also been found to have a considerable degree of dependence on porosity. Data shows that both Vp and Vs correlate linearly with porosity and the velocities decrease with an increase in porosity (Fig-8).

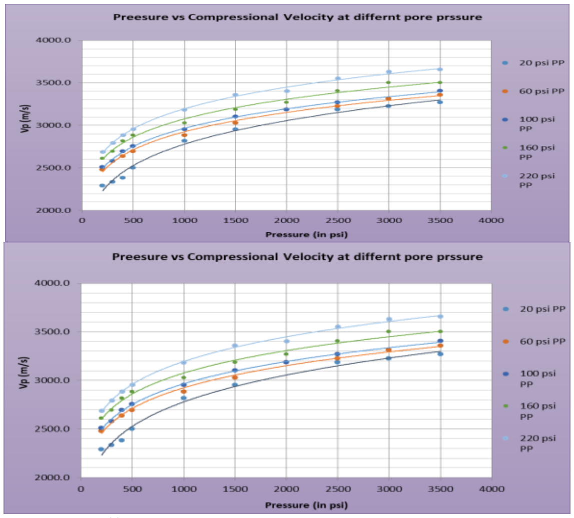


Figure 7. Effect on Compressional and Shear wave velocity at different pore pressure

The Vp-Φ and Vs-Φ cross-plots on a linear scale give the following relationships:

Pressure	Transform generated
200 psi	Vp = 3976.9-43.135 Φ Vs= 2068.7-17.943 Φ
3500 psi	Vp = 5495.5-209.81 Φ Vs = 2899.4-96.546 Φ

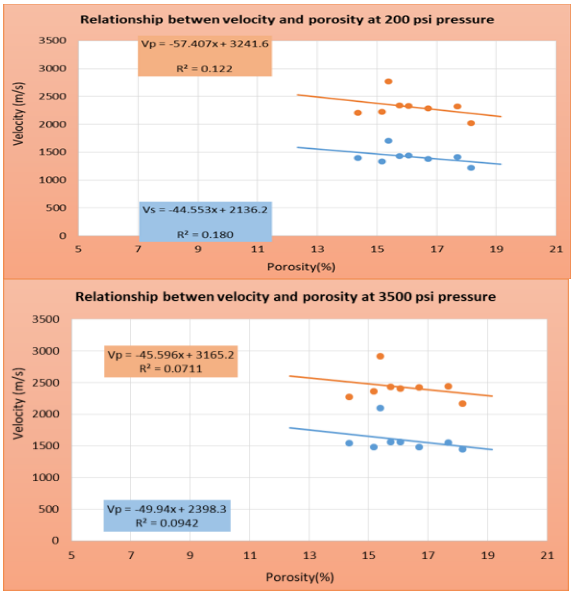
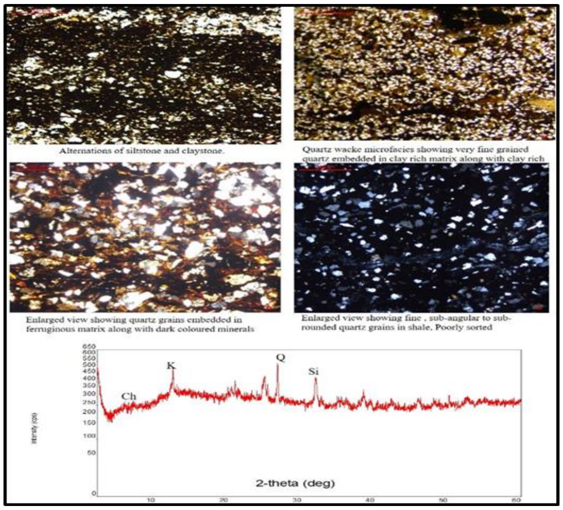


Figure 8. Compressional/ Shear wave velocity vs porosity plot 200 psi and 3500 psi

Sedimentological Microfacies analysis:

Core plugs studied are represented mainly by sandstones which are light gray, soft to moderately hard, massive, very fine to fine grained occasionally medium having moderate to good visual porosity. Sandstones are sometime interlaminated with shale and silty shale.

Petrographically, the sandstones are characterized by quartz wacke microfacies consisting of quartz. X-Ray Diffraction analysis for clay mineral identification indicates the presence of kaolinite. Bulk analysis of few samples indicates the presence of ilmenite and siderite (Fig-9).

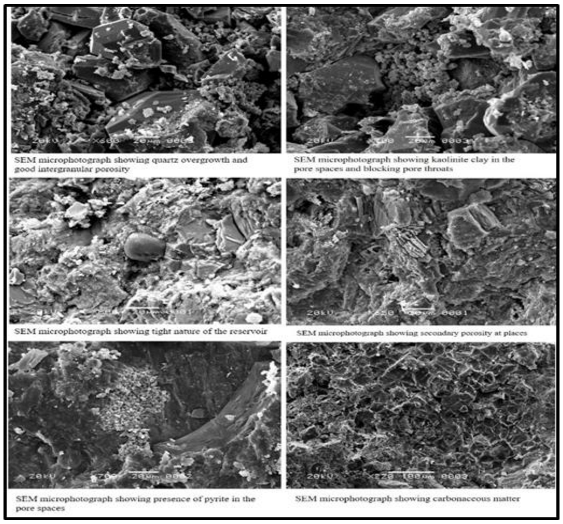

Alternations of siltstone and claystone.

Quartz wacke microfacies showing very fine grained quartz embedded in clay rich matrix along with clay rich

Enlarged view showing quartz grains embedded in ferruginous matrix along with dark coloured minerals

Enlarged view showing fine , sub-angular to sub-rounded quartz grains in shale, Poorly sorted

Figure 9. Microfacies and X-ray Analysis


SEM microphotograph showing quartz overgrowth and good intergranular porosity

SEM microphotograph showing kaolinite clay in the pore spaces and blocking pore throats

SEM microphotograph showing tight nature of the reservoir

SEM microphotograph showing secondary porosity at places

SEM microphotograph showing presence of pyrite in the pore spaces

SEM microphotograph showing carbonaceous matter

Figure 10. SEM Analysis

Scanning electron microscopic analysis reveals moderate to good inter-granular porosity which is partially affected by quartz overgrowth and pore-fill kaolinite Vermicular kaolinite occupying pore space and blocking pore throats has also been observed at places (Fig-10).

Integration of log analysis with core analysis:

The input parameters have been selected based on core derived sedimentological, petrophysical data and log attributes. Key wells have been evaluated through this standardized multi-mineral processing model Fig-11 to show how confining pressure affects the mentioned reservoir parameters and relates them to in-situ rock properties, thereby helping in realistic reservoir characterization, reducing uncertainty of estimated reservoir parameters and providing valuable input for the field development programs.

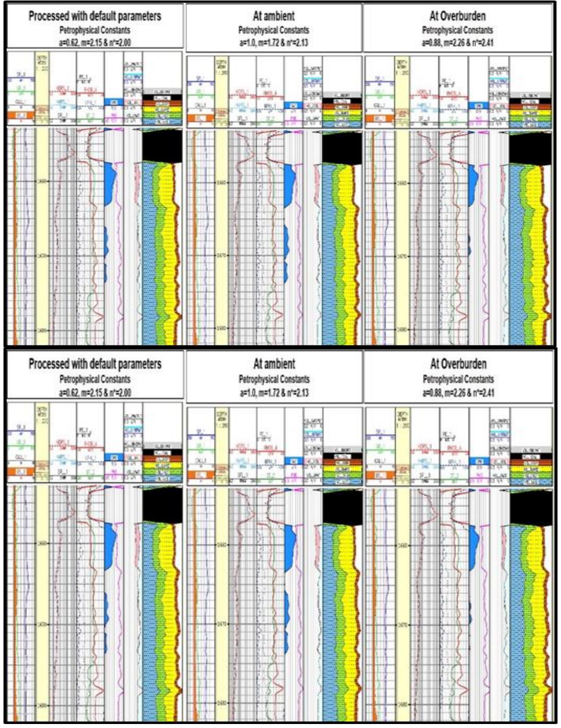


Figure 11: Multi-mineral processed output with default (a=0.62, m=2.15 & n=2.0) and standardized parameters a=0.88, m=2.26 and n=2.41

Fig-11 shows the comparison of the processed results amongst default, ambient and standardized parameters at overburden pressure. Processing with default petro physical parameters is unable to identify true fluid volumes. Reservoir characterization, therefore, is not realistic. The Reprocessing of the well logs with the standardized model by using the standardized core derived clay minerals and core derived petro physical parameters under in-situ pressure condition is able to identify and estimate the minerals and fluid volumes more accurately. The reservoir parameters, as a result also match well with the core derived and the initial production testing data leading to realistic reservoir characterization.

Conclusions

The present study has developed a standardized multi-mineral, petrophysical processing model for a heterogeneous clastic reservoir through integration of open hole log data with core determined petrophysical constants under in-situ pressure condition and mineralogical assemblage for realistic reservoir characterization. It is observed, that the petro physical constants ‘a’, ‘m’ and ‘n’ change significantly under in-situ pressure condition in comparison with their values under ambient condition. The study shows that the velocities increase as as the confining pressure is increases. The velocity changes with change in pore pressure also. Data shows that both Vp and Vs correlate linearly with porosity and the velocities decrease with an increase in porosity. Transform between Vp & Vs generated for ambient and in-situ pressure condition which may be used to evaluate shear velocity as where DSI log data is not available.

The standardized model under in-situ pressure condition helped to identify and estimate the minerals & fluid volumes accurately in the Sadra field of Cambay Basin. The resultant reservoir parameters match well with the initial testing data, thereby successfully addressing the challenges of inconsistency in production behaviour vis-à-vis log character in the study area

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