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Estimation of reservoir properties from well logs and core plugs to reduce uncertainty in formation evaluation: a case study from the Kohat-Potwar Geologic Province

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Formation evaluation and rock physics are powerful techniques to link the physical properties of rocks and pore fluids measured at boreholes with petrophysical, elastic, and seismic properties at boreholes or faraway from boreholes. However, several sources of uncertainty in the measurements of these properties can affect the strength of this link. A complete statistical workflow is proposed for obtaining petrophysical properties such as porosity, permeability, volume of shale, and water saturation at the well location. This workflow is based on the wireline logs and core plugs and is applied on the lower Jurassic siliciclastic reservoirs of Kohat-Potwar Geologic Province, Pakistan to determine its applicability, the advantages of the new integrated approach, and the value of uncertainty analysis. The linear regression relations are developed between several petrophysically derived parameters measured from core samples and calculated from well logs data. All these parameters are then used as input constraints in rock physics modeling to calculate seismic properties such as bulk and shear moduli, compressional and shear wave velocities etc. A linear relationship is established between porosity and seismic velocities obtained from rock physics model. The well logs predicted rock physics properties such as seismic (P and S-wave) velocities, effective densities and elastic moduli are in close agreement to those measured by using rock physics analysis. Statistical regression analysis revealed significant similarity in the porosity values obtained from geophysical well logs and core samples. The permeability of reservoir intervals show fairly strong linear relationship with the porosity, indicating that the reservoir interval of Datta sandstone is highly permeable and porous thus having large potential of hydrocarbon accumulation and production.

Introduction

Understanding and precise measurement of key reservoir properties like lithology, porosity, volume of shale, water saturation, permeability is primary goal of formation evaluation and reservoir estimation in petroleum industry. Generally it is assumed that the reservoir sand interval is homogeneous on some certain scale. However, on one hand, several forms of heterogeneity in reservoir parameters are present on different scales (Mavko et al., 2009). On other hand, the interaction between porous rocks and pore fluid also affect the petrophysical properties of reservoir rocks (Batzle and Wang, 1992; Khalid et al., 2014). Therefore, well understanding of the form and spatial distribution of these heterogeneities, the rock-fluid interaction and prediction of their impact on reservoir character is of great importance. Various theoretical models and empirical relationships have been suggested to map the rock-fluid interaction in reservoir rocks to delineate lithologies, fluid type and composition (Gassmann, 1951; Kuster and Toksöz, 1974; Brown and Korrington, 1975; Han et al., 1986; Tao and King, 1993; Gist, 1994; Gupta et al., 2012; Khalid and Ghazi, 2013; Khalid et al., 2014). However, most of these rock physics models have some limitations, thus can be valid and applied under certain checks and have need of some sort of specific properties as a feed which are not easily available or extracted from other geophysical data such as from wireline logs. As an example Gassmann (1951) model of homogeneous mineral modulus does not consider the pore geometry and valid only at low frequencies. Kuster and Toksöz (1974) model is valid under the assumption of isotropic and linear porous media. Brown and Korrington's model (1975) does not describe the ultrasonic lab conditions very well. Han's relations (Han et al., 1986) are dependent on confining pressure and fairly stable above 10 MPa. Therefore, the prediction of reservoir parameters and their accurate estimation from well logs is one of the central questions to geoscientists.

Most of the sand reservoirs have single porosity system of relatively homogeneous lithology on macro-scale. However, on micro-scale reservoir properties are heterogeneous (Barton et al., 2004; Mavko et al., 2009). This heterogeneity outcomes from physical and chemical reorganization processes over time, which complicates the reservoir characterization. Thus, the resulting reservoir properties incline to dif-

fer as a function of spatial localities vertically and laterally. These heterogeneities result in large uncertainty in the reservoir properties estimated by different methods.

The derivation of petrophysical parameters is an inverse problem which requires an integrated approach. The solution of an inverse problem is not limited to a deterministic estimation of the solution which is supposed to be optimal in terms of best-fitting of the given dataset, but it also include the evaluation of the uncertainty of the inversion results. The improvement in reservoir characterization is very important to minimize the risk of drilled dry holes (Han and Batzle, 2002). This improvement is by the combine effort of wireline logs and core data with quantitative interpretation of wireline log data (Grana et al., 2012). The porosity, volume of shale, water saturation and hydrocarbon saturation are the main results obtained from the quantitative interpretation of geophysical well logs such as resistivity, gamma ray (GR), acoustic, density and neutron. Although several improved approaches along with optimized sets of equations exist to estimate these measurements (Fylling, 2002; Heidari et al., 2010), however, some uncertainty in the inferred parameters is always present because small error in any measurement may produce uncertainty in the final output (Fylling, 2002; Viberti, 2010). Theoretical models used to determine petrophysical properties may also produce the uncertainty in the final values. Thus, a statistical analysis is performed to establish the reliability in the obtained results.

Relationship between petrophysical properties and rock physics parameters of a reservoir rock are well established (Wyllie et al., 1956;

Domenico, 1984; Winkler and Murphy, 1995; Mavko et al., 2009). Rock physics modeling is a helping tool mainly used to build up a relationship between petrophysical parameters estimated from well logs and core data, and seismic parameters of fluid (brine/hydrocarbon) saturated rocks. The uncertainty and percentage error in formation evaluation and reservoir rock properties is penetrated through the well-calibrated rock physics model, used to link petrophysical properties with seismic properties of reservoir rock. Mukerji et al. (2001a) gave the concept of statistical rock physics. Generally, in rock physics modeling a set of well-defined relationships are used that can translate petrophysical parameters into seismic properties. Fluid substitution is an important part of rock physics modeling, which make easy to differentiate reservoir fluids nature and its quantity in porous rock. Various kind of fluid substitution models are in practice (Mavko et al., 2009) to describe the relationship between the bulk modulus of the fluid-saturated rock (K_{sat}), the modulus of rock-forming minerals (K_m), the bulk modulus of the drained (or dry) rock (K_{dry}), and to the adiabatic bulk modulus of fluid (K_f) present with pore spaces. However, Gassmann (1951) fluid substitution model is generally used to express the relationship between all above mentioned parameters.

The main objectives of this work include determining the numerous reservoir properties and to reduce the percentage error and uncertainty related with various kinds of measurements in the two wells A and B in the western part of the Potwar Plateau of Pakistan (Fig. 1) where exact prediction of petrophysical parameters is a big issue because of very complex tectonic settings (Khalid et al., 2015). The

Figure 1. Location and geological map of the study area. A and B represent the well locations used in this study.

main focus is the assessment of the percentage error and uncertainty in the estimation and calculation of each parameter to provide a reliable value of each parameter. The wireline log data will be compared with the core data to minimize the uncertainty and to enhance the accuracy in the measurements. This work covers the applications of basic procedure to find out petrophysically derived parameters and rock physics modeling to link these calculated parameters with physical properties of rock-fluid composite and the statistical approach to analyze the error. A simple and complete statistical workflow is proposed to correlate core plugs with wireline log data. Linear statistical relationships are developed and implied between numerous reservoir parameters to evaluate percentage error and uncertainty in the measurements of different quantities.

Data and Method to Extract Reservoir Parameters from Core-log Integration

All kind of wireline logs including gamma ray (GR), resistivity (LLD), sonic (DT), caliper, density (RHOB) and spontaneous potential (SP) logs run in both wells are used in this study. Total 44 core plug samples of well A taken in the interval of 4595 m to 4627 m and 53 of well B in the interval of 4705 m to 4760 m are also analyzed to measure uncertainty in petrophysical and rock physics parameters. The flow chart of the methodology is shown in Figure 2. In this work, we consider the case of consolidated or poorly consolidated siliciclastic rocks. Heterogeneity in rock composition, pore shapes, interbedded thin shale layers, effect of invasion, pore fluid types and saturation levels, fluids distribution pattern, cracks and their orientation, grain packing, pore networks and other chemical and physical properties of both fluids and solids, calibration issues etc. are possible sources of

uncertainty in petrophysical parameters and quantitative formation evaluation. It is difficult to draw a scale of effectiveness of the heterogeneity features. All features have their own significance and can influence the petrophysical properties depending upon the area, geology, compaction, depositional environment etc. In shallow and soft reservoirs having high porosity, fluid saturations may have substantial effects on seismic and petrophysical parameters. To measure these uncertainties statistical regression analysis is also done. Crossplots among different petrophysical parameters were also prepared to verify log calculated values against those derived from core analysis.

Petrophysical Parameters Measurements

Volume of shale (V_{sh}) is one of the most important petrophysical parameter, required to define reservoir quality as well as reservoir character. Shale volume was calculated to approximate clay contents in the reservoir rock. It may affect the water saturation in the reservoir. Gamma ray (GR) log was used to estimate V_{sh} . The volume of shale was also estimated by petrography of the core samples. The computation of porosity from log has need of lithological information, core data and laboratory analysis, such as the properties of the pore fluid and grain matrix. In next step, the porosity of reservoir interval is found and corrected by using density and neutron logs. These porosities are then compared to those measured from core plugs.

The water saturation (S_w) measurements taken in open hole with resistivity logging are fundamental to quantify hydrocarbon saturation (S_h), original oil in place (OOIP) or original gas in place (OGIP) volumes. In reservoir parameters estimation, the exact determination of S_w with accuracy is very challenging because there are a number of factors that can affect the values of S_w (Tiab and Donaldson, 2004; Ahmed et al., 2017). Several independent methods that can be used to estimate S_w can lead to somewhat changed S_w values that may lead to considerable differences in OOIP or OGIP volumes. Therefore, it is a big task to select an appropriate method to find out accurate value of S_w and its distribution throughout the reservoir sand interval. Following equation proposed by Archie (Archie, 1942) is used to find out water saturation in clean sand intervals by using resistivity log:

$$F = a/\phi^m, \quad (1)$$

$$S_w = \left(\frac{a R_w}{\phi^m R_f} \right)^{1/n}, \quad (2)$$

where F is formation resistivity factor ($F = R_0/R_w$, R_w = brine-water resistivity, and R_0 = rock resistivity with $S_w = 1.0$), while a , m and n are cementation constant, the cementation exponent and saturation exponent respectively. In the above equation, R_f is the true resistivity of formation at given fluid saturation. From Equation (2), it is clear that the water saturation (S_w) is inversely proportional to true formation water resistivity (R_f). Shaley rocks have lower values of R_f , therefore, the amount of S_w increases with the increase of volume of shale (V_{sh}). On the other hand, shale volume has inverse relation with formation resistivity factor (F) and S_w has direct relation with F and increases with increase in F .

Figure 2. Flow chart of the methodology used in this study.

Relationship between Petrophysical and Rock Physics Parameters

The algorithm of rock physics model starts with the determination of elastic moduli such as bulk and shear moduli of pore fluids and solid matrix, afterword, the elastic moduli of dry rock or rock frame are computed. Various models differ for the estimation of the dry rock moduli (Murphy et al., 1993; Pride et al., 2004; Zinsner, 2007). In this work, dry rock bulk and shear modulus of rock frame are estimated by using formula given by Murphy et al. (1993). Finally, Gassmann fluid substitution model (FSM) is used to quantify the effect of fluids present within reservoir pore spaces on porous rock properties. The Gassmann's relation for saturated bulk modulus in the simplest form is:

$$K_{sat} = K_{dry} + \alpha^2 M^{-1}, \quad (3)$$

where α is the Biot's coefficient (Biot, 1941) or also called coefficient of effective stress

$$\alpha = 1 - K_{dry}/K_m, \quad (4)$$

is always has numerical value less than 1 in real porous and permeable medium and it is a complex function of number of voids (porosity), pore geometry, clay content, grain size, mineralogical composition of rocks under study etc. (Hilterman, 2001; Mavko et al., 2009). The modulus

$$M = \frac{\phi}{K_f} + \frac{\alpha - \phi}{K_m}, \quad (5)$$

is defined as the pressure needed to force fluid into formation without changing volume (Russell et al., 2003) and f is rock porosity. The compressional wave velocity (V_p) and shear wave velocity (V_s) are found out by

$$V_p = \left(\frac{K_{sat} + 4\mu/3}{\rho_{eff}} \right)^{1/2}, \quad (6)$$

$$V_s = \left(\frac{\mu}{\rho_{eff}} \right)^{1/2}, \quad (7)$$

where,

$$\rho_{eff} = (1 - \phi)\rho_m + \phi\rho_f. \quad (8)$$

In the above equation, ρ_{eff} is the effective rock density saturated with fluids, while ρ_m and ρ_f are being the rock forming mineral and pore fluid densities, respectively. If porous media contains more than one fluid or multi-phase fluid then the fluid modulus and density are equal to the arithmetic average of every single fluid phase (Khalid et al., 2014).

$$K_f = \left[\sum_{k=1}^m \frac{S_k}{K_k} \right]^{-1}, \quad (9)$$

$$\rho_f = \sum_{k=1}^m S_k \rho_k, \quad (10)$$

where r and S represent the density and saturation of the fluid phase denoted by sub index k and m which are the total number of fluid phases may present in pore spaces.

Similarly, K_{sat} was calculated directly from sonic and density logs data by using following relation.

$$K_{sat} = \rho_{eff}(V_p^2 - 4/3 V_s^2). \quad (11)$$

The results of FSM and wireline logs were compared. Statistical analysis is done to quantify the error and uncertainty.

Quantitative Estimation of Petrophysical Parameters

The above narrated quantitative work flow has been applied on two real data sets from two exploration wells, Western Potwar Plateau, Pakistan. Both wells were drilled vertically in a deep clastic reservoir of Jurassic age made by soft sandstones of a turbidite channel complex. The prospect is a typical structural with complete developed petroleum system (Khalid et al., 2015). The core analysis and petrophysical interpretation reveals that sparse shale beds are also present and the sandstone is composed by 60–70% quartz and remaining is clay and other minerals. The clay is a mixture of illite and kaolinite (respectively 60% and 40%). The reservoir fluid is oil and brine. The determinations of reservoir quality and formation evaluation are mainly depending on the accuracy of quantitative evaluation of petrophysical parameters. The comprehensive set of wireline logs including GR, density, resistivity, sonic and neutron of high resolution is used to provide reliable formation evaluation. Globally, the quality of data is good (Fig. 3). Wireline logs and core data are combined together for quantitative formation evaluation. The qualitative identification of reservoir zones was made by the log signatures from shale beds and compact beds. Beds with high GR, high neutron values, low resistivity and low density values indicated shale and were thus eliminated. The quantitative identification of the reservoir zones was done by volume of shale and clay, porosity and fluid content determinations through the use of empirical relationships already mentioned in previous section.

Volume of Shale

At first step, the gross lithological facies were marked by using GR and SP logs. These lithologies were confirmed through other logs such as resistivity, sonic, and density-neutron. After confirmation of lithologies the volume of shale (V_{sh}) was computed from GR log using gamma ray index (I_{GR}) with the help of Clavier (Clavier et al., 1977), Stieber (Stieber, 1970), and Larionov (Larionov, 1969) equations. The volume of shale computed via the equations proposed by Clavier, Stieber and Larionov in the intervals of Datta sandstone encountered in wells A and B is plotted in Figures 4a and b. The values of V_{sh} computed by the above mentioned equations are in close agreement, especially at lower values of I_{GR} . However, V_{sh} by Clavier and Larionov are closely matched in the whole interval of I_{GR} in both wells. The relative error in V_{sh} by Clavier and Stieber is upto 15% for large values of V_{sh} ($V_{sh} > 50\%$). The mean values of V_{sh} in well A and well B are completely overlaps for all values of I_{GR} (Fig. 4c). The relationship between V_{sh} and I_{GR} is determined using a non-linear regression with regression coefficient $R^2 \sim 0.999$. The average value of V_{sh} in the zone is 14–18% in well A whereas in well B, it is much lower (6–8%), which shows that the reservoir in well B is clean sand whereas in well A it is with shaly sand beds. The petrographic analysis done by using XRD of core samples confirms these values. The average volume of shale in well B is sufficient low to allow for free fluid flow.

Figure 3. Wireline logs of well A and well B showing the quality of sand reservoir.

Figure 4. Crossplot between gamma ray index (IGR) and volume of shale (V_{sh}) in well A (a) and well B (b) computed by using various relationships. (c) Mean values of V_{sh} in wells A and B.

Porosity and Permeability

The Dresser Atlas (1979) proposed relationships to find out porosity were used and the calculated porosity was corrected from density and neutron logs. The porosity measured from core samples and core density and log porosity and log density are plotted in Figures 5a and b along

with their regression relations. The porosities in both wells vary in a large interval. A linear regression is developed to determine the correlation between porosity and density by geostatistical technique.

$$\rho = -m\phi + c, \quad (12)$$

where r is the formation bulk density, m and c are the coefficients to

Figure 5. Crossplot between density (log and core) and porosity (log and core) for well A (a) and well B (b).

be determined by least-square regression. The coefficient m represents the gradient in porosity with respect to density. Log and core porosities decrease with increase in density, thus a linear relationship exists between porosities and densities of Datta sandstone. A very close agreement exists between log porosity and log density and core porosity and core density with 0.96 regression coefficient (R^2) value in well A (Fig. 5a). In well B, log porosity and log density and core porosity and core density are fairly close to each other with $R^2 \sim 0.925$ (Fig. 5b). The average porosity value in the selected interval for well A is 30% and for well B is 25%. The lower values of porosity in well B are due to reservoir depth and overburden pressure. This decrease resulted mainly from rearrangement of grains during burial. The permeability of sandstone encountered in both wells is crossplotted with porosity (Fig. 6). The permeability shows higher values against higher porosities, which indicates that the reservoir sandstone is highly per-

meable. Thus the pore fluids or hydrocarbon can easily move within the pores.

Water-saturation Uncertainty

The fluid saturation of a reservoir is basically the amount of all fluids present into the pores. Generally, hydrocarbon (oil/gas) and water are present into the pore spaces. The water saturation (S_w) therefore is the portion of pore volume filled by formation water. The S_w determination is the main objective of both core analysis and borehole log interpretations. Decisions regarding the commercial production of oil or gas from a reservoir interval mainly depend on the formation water saturation. Thus the accurate measurement of water saturation is important. Uncertainty analysis was done on the core samples to find out the influence of each parameter on S_w . The value of m had much more influence than other parameters. Archie proposed $a = 1.0$ and $m = 1.8-2.0$ for his data set. However, in our case the values of a and m for Datta sandstone are 0.65 and 2.1 respectively. These values are computed by regression analysis of core porosity and formation resistivity factor. The water saturation computed by the resistivity logs in A and B wells is plotted in Figure 7 against depth. S_w in well A are slightly higher than of well B.

Rock Physics Parameters

The results of rock physics analysis is calibrated at well localities, by comparing the velocity and density estimated from FSM (Eqs. 6 and 10) with the velocity and density from the recorded logs (sonic and density respectively) in the borehole.

Log and core derived petrophysical parameters obtained at in-situ conditions of pore pressure, water saturation, volume of shale, temperature etc. utilized in rock physics modeling as essential ingredients. FSM is applied under the assumption of homogenous distribution

Figure 6. Porosity and permeability cross plot for well A and well B.

Figure 7. Water saturation in well A (a) and B (b).

Table 1. Reservoir parameters used in FSM

	Well A	Well B
Reservoir interval	4600–4630 m	4705–4760 m
Average reservoir temperature (K)	404	409
Average effective pressure (MPa)	40	40
Fluid parameters		
Oil API	34	34
In-situ oil density (g/cm ³)	0.8855	0.874
Gas to oil ratio (Litre/litre)	288.102	271.15
Bulk modulus of oil (GPa)	1.4711	1.2942
In-situ density of brine (g/cm ³)	1.181	1.169
Bulk modulus of brine (GPa)	2.095	2.11
Rock parameters		
Bulk modulus of Quartz (GPa)	37	37
Bulk modulus of Clay (GPa)	21	21
Density of Quartz (g/cm ³)	2.65	2.65
Density of Clay (g/cm ³)	2.58	2.58

of fluids within the pores. The applied FSM requires the following input data: pore fluid and matrix properties, reservoir temperature and pressure. Fluid parameters and reservoir condition information are generally available from pressure-volume-temperature (PVT) analysis and well tests measurements, whereas solid-phase properties are inferred from core mineralogical analysis. The parameters used as input for fluid substitution modeling (FSM) are given in Table 1.

Significant predictive relationships are found between porosity and seismic parameters (density, velocities, and acoustic impedance, bulk and shear moduli) of Datta sandstone. The seismic velocities derived from sonic log are compared with the velocities estimated by FSM for both wells A and B are shown in Figures 8a and b respectively. As expected, P-wave velocity (V_p) shows good correlations with porosity. The P-wave velocities (V_p) derived from sonic log (DT) are in very similar to those estimated by FSM with small error (Fig. 8c). The bulk modulus derived from wireline logs by using Equation (11) is compared with K_{sat} of FSM by using Equation (1) against porosity values for both wells A and B (Figs. 9a and b). For wireline log based K_{sat} , the input P-wave velocity, density and shear modulus are those extracted from sonic, density and shear logs respectively. The relationship in studied wells with strong correlation coefficient is found.

Figure 8. Log derived compressional wave velocity (V_p) and fluid substitution model velocity as a function of porosity in well A (a) and well B (b). (c) Percentage error in log derived V_p and FSM derived V_p in both wells.

Figure 9. Bulk modulus of rock-fluid composite (K_{sat}) derived from logs and from fluid substitution model as a function of porosity in well A (a) and well B (b).

Discussion

The determination of accuracy in reservoir parameters prediction is an important step in formation evaluation. Although some workers has been addressed the uncertainty in geophysical inverse problems (Jackson, 1979; Tarantola, 2005), but it is generally ignored in formation evaluation. In this work, the proposed methodology to reduce uncertainty in reservoir parameters is successfully applied on two wells. The uncertainty analysis was performed at the well location by integrating wireline logs, core plugs and rock physics modeling by means of a statistical approach. The real field data including wireline logs and core plugs from an oil field in the western Potwar geological province was used to estimate reservoir properties and rock physics modeling.

A sequence of equations for the prediction of reservoir parameters of Jurassic Datta sandstone is developed by correlating wireline logs calculations with core measurements. A relationship, based on regression analysis, is proposed to estimate shale volume (V_{sh}) with the help of gamma ray index (see Fig. 4c). The average values of shale volume in well A were ranged from 14–18% which converted to volume of sand 82–86%. In well B, the average value of volume of shale is 6–8% support that reservoir consist of clean sand dominating lithology. The shale values in the well B are sufficiently low to allow free flow of hydrocarbon and effect of water saturation (S_w) and clay bound water is low in the reservoir interval. The density log (RHOB) was taken to calculate reservoir porosity, and compared it with the core plugs measurements (Figs. 5a and b). From the figures it is clear that porosity from core-plugs or logs is decreasing with increase in density, thus showing a non-linear trend. In the same type of rock, density increases due to increase in compaction and reduction in pore spaces. Thus a non-linear trend of density with porosity either core-plugs or logs exists. Porosity is decreasing with increase in density in both

wells in whole interval of sand reservoir. The average porosity values in sandstone intervals are 26% and 30% in well A and well B respectively. Similar observation of porosity value was made by Khalid et al. (2015) in Datta sandstones of Western Potwar area. The average permeability of these intervals ranges from 650 md to 989 md shows that the reservoir is highly permeable with excellent potential of hydrocarbon accumulation. These average porosity and permeability are good to permit hydrocarbon to flow freely. The average water saturation in well A is 0.29 and in well B it is 0.21, thus the high saturation of hydrocarbon. Average hydrocarbon movability index in both wells is form 0.23–0.31 indicate that hydrocarbon is moveable. It is worth mentioning that the methodology adopted in this work is the integration of the rock physics modeling and petrophysical analysis. The rock physics modeling is based on the elastic model (Gassmann fluid substitution) and its isotropic form is used by considering homogeneous, linear and elastic material. Brown and Korringa (1975) extend the Gassmann's model to anisotropic reservoirs. The basic assumptions for the rock physics model used in this work includes: composite rock unit is macroscopically isotropic, pores are communicated, pore must be filled with frictionless fluids and does not interact with rock matrix to soften and harden the fram. The main advantage of this integration is to link between elastic and petrophysical properties of the rock-fluid composite, which reduced the uncertainty in reservoir properties prediction. Since the objective of this study is to reduce the uncertainty in petrophysical parameters of a reservoir. Rock physics parameters can be derived from petrophysical analysis such as density, elastic moduli of rock-fluid composite, velocities etc. Similarly, petrophysical parameters can also be inferred from rock physics models e.g., porosity, density of formation fluid, fluid modulus, fluid saturation etc. The purpose of integration of rock physics modeling and petrophysical analysis is to enhance the accuracy in the computation of these parameters. Sonic logs can be used as well for prediction, instead of rock physics modeling. However, sometimes the correla-

tion between sonic logs and petrophysical values is not always optimal in well-log analysis. Moreover, the resolution of sonic travel time logs is generally poor than the resolving power of geophysical well logs used in reservoir characterization and formation evaluation analysis. On the other hand, the values of rock physics modeling are in a complete consistent with petroelastic results. The elastic moduli and velocities obtained from the rock physics modeling (Eqs. 3–10). Various rock physics parameters (bulk moduli, velocities etc.) were estimated by using petrophysical parameters such as porosity, density, fluid saturation etc. For instance, sonic log was used to compute P-wave velocity (V_p) in reservoir interval and due to the non-availability of shear log, shear (S-wave) velocity (V_s) is computed using Castagna's well-known formula (Castagna et al., 1985). The compressional waves can travel through the fluids because fluids have bulk modulus (change in volume due to pressure exertion) and compressional velocity, dependent on fluid's density and modulus. In the present study, we have computed the P wave velocity in the reservoir fluids at in-situ conditions. The P wave velocities in reservoir fluids (brine/oil) present in wells A and B are 1590 m/sec, 1559 m/sec (for brine) and 1350 m/sec and 1285 m/sec (for oil) respectively. The compressional wave velocity is directly linked with the bulk modulus of pore fluids and therefore brine saturated rocks have higher P wave velocities as compared to oil saturated rocks. In order to verify predicted accuracy in results, Figure 8c displays an error (percentage) analysis for compressional wave (P-wave) velocities, which is 6% maximum. V_p decreases linearly with increase in porosity in both wells. The P-wave velocities obtained in well A lie in the range of 4140–5320 m/s whereas in well B are in the range of 4205–5340 m/s. This difference in velocity values, which has been even detected in one rock type with similar porosity, is may be due to different factors like burial depth, number of openings, orientation of cracks, type and pressure of fluids in pore spaces. The P and S wave velocities are strongly dependent on burial depth, the increase in burial depth results in high compaction and finally an increase in P wave velocities. In well B, reservoir sand is located at comparatively higher depth and therefore has higher P wave velocity. Reservoir porosity (number of openings) and velocities are inversely related to each other and reservoir porosity varies spatially and vertically due clay content, grain sorting and deposition process. P wave velocity is also affected due to pore fluid types and their saturation levels. Due to lower modulus of gas, the water saturated rocks are always having higher V_p as compared to gas saturated rocks. The pressure of fluids present with the pores (pore pressure) has inverse relation with seismic compressional velocities and high pressure zones show reduced velocities. Similarly, orientation of cracks also affects the P wave velocity and seismic velocities have less travel time when travel along the direction of cracks and vice versa.

Conclusions

An integrated approach to estimate reservoir parameters and formation evaluation is very effective to minimize the error in these measurements. In this work, a workflow with the help of statistical analysis is proposed to find out reservoir parameters from geophysical well logs and core samples with large accuracy. The mean values of volume of shale (V_{sh}) in these wells are relatively low, which show that the reser-

voir is shaly sands to clean sand grade. The porosity and permeability are high; indicating the quality of reservoir is very good and formation fluid is movable. Linear relationship is found between density and porosity in both wells A and B. The core plugs porosities provide better match with log porosity thus decrease the uncertainty in the measurements. Logs derived velocities (compressional or P-wave) are in very close agreement to those estimated from rock physics (fluid substitution modeling) analysis. The P-wave velocities predicted from both wells (A and B) are very alike to each other. These velocities were presumed because of their closeness and the same interpreted sandstone reservoir. However, V_p predicted by rock physics model is somewhat higher than derived from sonic logs.

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