Petro-elastic Modelling and inverse-Q Estimation for Fluid Discrimination

Wasiu Olanrewaju Raji
Earth, Energy, and Environment (EEE) Research Group, Department of Geophysics,
University of Ilorin, Ilorin, Nigeria

ABSTRACT

Theoretical studies and laboratory experiments have shown that seismic attenuation (or inverse quality factor Q^{-1}) is sensitive to the presence of fluids, degree of saturation, porosity, and pressure in porous elastically heterogeneous rocks. However, the use of attenuation for reservoir characterization is yet to be established using wire line data. This study applied the fundamental theories of petro-elasticity and inelasticity to test the sensitivity of P- and S-wave inverse quality factor to the presence of fluids in porous rocks saturated with two or more fluids using a set of data from Gulfak Field, North Sea, Norway. P-wave and S-waves inverse quality factor were estimated from well logs using some classical rock physics models. The results showed that the differential response of P- and S-wave quality factor parameters and their hybrids can be used to discriminate fluids and lithology. P-wave inverse Q factor is generally higher in hydrocarbon saturated rocks than in brine/water saturated rocks, while the S-wave inverse quality factor does not show direct sensitivity to fluid. A cross plot of the ratio of P-wave and S-wave inverse quality factor, Q_P^{-1}/Q_S^{-1}, with the ratio of P-wave and S-wave velocities, V_P/V_S, in the reservoir interval distinguished gas sand from water sand, and water sand from oil sand. Gas sand is characterized by the highest $\frac{Q_P^{-1}}{Q_S^{-1}}$ and the lowest $\frac{V_P}{V_S}$ ratios; oil sand is characterised by the lowest $\frac{Q_P^{-1}}{Q_S^{-1}}$ and the highest $\frac{V_P}{V_S}$ while water sand is characterized by $\frac{V_P}{V_S}$ and $\frac{Q_P^{-1}}{Q_S^{-1}}$ values that plotted between those of the gas and oil sands. The study showed that inverse quality factor analysis in wire line data can be used to compliment the routine procedures (e.g., bright spots, AVO) in order to reduce uncertainties in the search for hydrocarbon accumulation.

Keywords: Inverse Quality Factor; P-and S-Wave Attenuation, Elastically Heterogenous Rock; Velocity ratio.

INTRODUCTION

Attenuation analysis of recorded well logs can provide crucial dimensions to the existing exploration techniques (e.g., Amplitude-versus-Offset, AVO) if realistic rock physics models for the static and dynamic reservoir properties are available. Without a good understanding of the geology and the underlying rock physics, it is impossible to interpret the time variant changes in pore-pressure and saturation (Andersen *et al.* 2009; Raji and Rietbrock, 2013a; Raji 2015a). The effect of pore fluid changes can be estimated from the rock and fluid properties obtained in recorded well logs and the mineral composition obtained from geological formation using theoretical rock physics relations. The changes of pore fluid or the saturation level can be related to the petro-elastic properties of the rock, using the rock physics model of Gassmann (1951) or Mavko *et al.* (1995). Therefore, changes in rock modulus with frequency (modulus-frequency–dispersion) can be linked to the inverse quality factor (Q^{-1}) via the standard linear solid equation, SLS Mavko *et al.* (1998). P- and S-wave inverse–Q logs can be computed from well data as the difference between the high frequency petrol-elasticity and low frequency petro-elasticity of the rock, using the Kramers-Kronig relation and the standard linear solid model (Mavko *et al.* 1998; Dvorkin and Uden 2004; Dvorkin and Mavko 2006).

At low frequencies, a pore-scale fluid distribution is assumed for the rock. The petro-elasticity (or modulus) of the rock at low frequency is estimated as a function of the bulk modulus of the mixture of the pore fluids. The bulk modulus of the pore fluid mix is the harmonic average of the modulus of the individual fluids present in the rock. At high frequency, patch-scale fluid distribution is assumed for the rock. The patches and the region surrounding them are saturated with different fluid types. The petro-elastic property of the rock (or rock modulus) at high frequency

The author thankfully acknowledges the Department of Earth Sciences of the University of Liverpool for facilitating the release of the data used for this study and NAPE for organising the conference where this study was presented.

is therefore estimated as the harmonic average of the bulk moduli of the patches and the surrounding region. Inverse – Q can be estimated in well data using these theories if information regarding porosity, saturation, density, and clay or shale volume is available from the well log records, and the parameters relating to the fluid and dry rock properties (e.g., bulk modulus of fluid, density of fluid, dry rock modulus) are obtained from the literature that are specific to the area under investigation (Klimentos and McCan 1990; Duffaut, *et al.* 2001; Mavko and Dvorkin, 2005; Raji, 2010). Attenuation analysis supported by rock physics models that are based on plausible geological model can serve as a direct hydrocarbon indicator, and it can potentially guide exploration decisions where common exploration techniques (e.g., AVO) failed to yield reliable results.

Elastic wave parameters (V_P, V_S and ρ)) respond differently to pore fluid and rock mineral matrix (Raji and Rietbrock, 2013b, Raji 2015b). The differential response of these parameters and their hybrids can be used as a preliminary diagnose for fluid and lithology to direct further study. The velocity of seismic waves propagating through a rock can be strongly impacted by fluid distribution in the rock (Endres and Knight 1991; Knight *et al.* 1998; Cadoret 1993; Mavko and Nolen-Hoeksema 1994). Bulk modulus (k), Lame's first parameter (λ), shear modulus (μ) (also known as Lame's second parameter), and compressional modulus (M) are the petro-elastic parameters that are used to analyse the petrophysical sensitivity of the rocks in this study. Compressional modulus is a hybrid of the bulk and shear moduli. Apart from being basic ingredients for inverse-Q analyses in well log data, the moduli are on their own sensitive to pore fluid and rock mineral matrix (lithology). Consequently, Inverse–Q measurements in recorded well logs using the standard linear model and the Kramers-Kronig relation have been carried out by Dvorkin *et al.* (2006) and Mavko *et al.* (2005). The differences between the work presented in this paper and those mentioned above are as follows: (i) Dvorkin *et al.* (2006) and Mavko *et al.* (2005) measured attenuation in complete well logs recorded in the Gulf of Mexico. This paper shows how inverse – Q can be estimated in well logs with incomplete datasets, and thus engaged some quantitative models to compute the required but missing data; (ii) this study presents a robust method of combining elastic and anelastic properties of P- and S-waves to distinguish fluids in rocks; (iii) the analysis is applied to a dataset from a different geological setting -Gullfaks field, North Sea, Norway.

This study shows how the elastic and inelastic properties of P-wave and S-wave estimated from log data recorded in well A-10 of the Gullfaks field, North Sea, Norway, is applied to the analysis of the rocks and fluids penetrated by the well. The study applies the sensitivity of some rock-fluid elastic modulus (Bulk modulus, Shear modulus, Lame's first parameter and compressional modulus) to characterise the lithologies and fluids penetrated by the well. Following this, a robust technique of combined elastic and inelastic properties of P- and S-waves is used to distinguish gas from oil, and oil from water. The paper ends with an overview of the discussions and a conclusion. Inverse–Q is a term here used to describe seismic attenuation measured in well log data. Petro-elasticity and elastic modulus are used interchangeably in this paper. The words attenuation and inverse quality factor are used interchangeably in this paper.

METHODOLOGY

Petro-Elastic Analysis of Rock Fluids

An important goal of petrophysical analyses is to obtain accurate rock physics parameters to discriminate pore fluids and lithologies. The three basic independent elastic parameters that are readily obtained from well logs are the P-wave velocity (V_P), S-wave velocity (V_S) and Density (ρ). These three fundamental rock properties can be combined to extract other rock properties that are useful to the study lithologies and pore fluids. The elastic properties of rocks can be classified into S-type and P-type parameters (Yuedong and Hongwei 2007). S-type parameters are the parameters that are not sensitive to the presence of fluid (because shear stress cannot transmit in fluids). Examples of S-type parameters include S-wave velocity, S-wave impedance and shear modulus. Parameters such as P-wave velocity, P-wave impedance, bulk modulus, Lame's first parameter are sensitive to fluids, and they are generally known as P-type parameters. Some of the S-type and P-type parameters and their hybrids will be used for the well analyses with the goal of delineating fluid saturated regions and indicating changes in fluid and lithology.

The well data used for this study is Well A-10 from the Gullfaks Field, North Sea Norway (Fig.1). It consists of gamma, porosity, and permeability data covering a depth interval from 1500m to 2416m. The well penetrated two sandstone series separated by a shale unit. Some quantitative models are used to estimate the missing data. the model of Timur 1968; Rider, 1986, and Hilterman, 2001 were used to compute the well data required for the analysis. Starting from the log data shown in the first three frames of figure 1, clay volume (V_{clay}) is predicted from the Gamma log using the model proposed by Rider (1986).

$$V_{clayL} = \frac{GR(value) - GR(min)}{GR(max) - GR(\text{min})} \tag{1}$$

Where *GR(value)* is the value of gamma ray. *GR* (*min*) and *GR* (*max*) are ththe minimum and maximum gamma ray

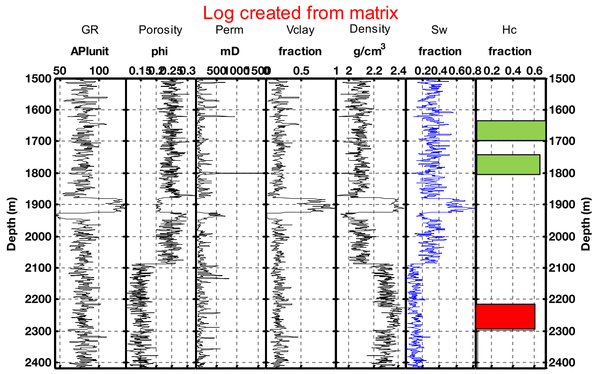


Figure 1: Well log curves: Shown from left to right are: Gamma ray log, Porosity log. Permeability log, Clay volume log, Bulk density log, Water saturation log and Hydrocarbon saturation log. The three logs are from Gullfaks Well A-10. Others log curves are estimated using some quantitative models. In Hydrocarbon log, green is gas and red is oil. See the electronic version for colour codes.

value, respectively, and V_{clayL} is the linear clay volume. The linearity in the estimated clay volume is removed as shown in equation 2

$$V_{clay} = \frac{V_{clayL}}{3-2V_{clayL}}. \quad (2)$$

V_{clay} is plotted in frame E of figure 1. Irreducible water saturation, S_{wirr} is predicted in the logged interval using the empirical relation proposed by Timur (1958).

$$S_{wirr} = 11.59\frac{\emptyset^{1.26}}{K^{0.35}} - 0.01, \quad (3)$$

where θ and k are the porosity and permeability, respectively. The estimated irreducible water saturation is assumed to be equal to the water saturation

$$S_W = S_{wirr}. \quad (4)$$

Water saturation is plotted in of figure 1. Hydrocarbon saturation (oil and gas) is plotted in frame (H). The bulk density, ρ_b, of the rock is then estimated (Hilterman 2001) as:

$$\rho_b = (1-\emptyset)\rho_{ma} + \emptyset S_{Water}\rho_{Water} + \emptyset S_{Gas}\rho_{Gas} + \emptyset S_{Oil}\rho_{Oil}, \quad (5)$$

where ρ_{ma}, ρ_{Water}, ρ_{Gas} and ρ_{Oil} are the density of the grain matrix, water, gas and oil respectively.
S_{water}, S_{Gas} and S_{Oil} are the saturations of water, gas and oil obtained from figure 1. Saturation is expressed as a fraction. The density of the rock matrix is estimated from the clay and quartz composition as:

$$\rho_{ma} = V_{Clay}\rho_{Clay} + (1 - V_{Caly})\rho_{Quartz}, \quad (6)$$

where V_{Clay}, ρ_{Clay}, ρ_{Quartz} are the clay volume, clay density, and quartz density, respectively. Densities of the rock grains, pore fluids, and bulk moduli of the fluid, as well as other parameters that are not obtainable from well data (but usually determined in the laboratory) were obtained from literature published on the Gullfaks field by Mavko *et al.* (1998), Duffaut *et al.* (2001) and Andersen *et al.* (2009). These parameters and their values are listed in the appendix. However, it is noted that bulk density indirectly estimated from porosity is u unreliable for this case study. The bulk modulus of the partially saturated rock, *Ksat* in the interval covered by the log suite is estimated using the formulation of Gassmann (1951).

$$K_{sat} = K_S\frac{\emptyset K_{DRY} - (1+\emptyset)K_F K_{DRY}/K_S + K_F}{(1-\emptyset)K_F + \emptyset K_S - K_F K_{DRY}/K_S} \quad (7)$$

The bulk modulus of the saturating fluid K_F is estimated as the harmonic average of the moduli of water, K_W and hydrocarbon, K_{hc} such that:

$$\frac{1}{K_F} = \frac{S_W}{K_W} + \frac{h_c}{K_{hc}}. \quad (8)$$

Where h_c is the hydrocarbon saturation and can be substituted with gas or oil saturation. The estimated bulk modulus is plotted with depth in figures 2. The shear modulus, μ is estimated using the formulation of Pride *et al.* (2004).

$$\mu = \frac{G_{ma}(1-\emptyset)}{(1-\gamma\alpha\emptyset)}, \quad (9)$$

Where, $\gamma = \frac{1+2\alpha}{1+\alpha}$.

Where G_{ma} is the shear modulus of the rock matrix (i.e., clay and quartz), and α is the consolidation parameter (Lee 2005). The estimated shear modulus is plotted with depth and shown in figure 3. The advantage of using the shear modulus formulation of Pride *et al.* (2004) is that it depends on the rock grain matrix, consolidation constant and porosity which are dry rock properties. This enables one to approximate the shear modulus of dry rock, μ_{DRY} to the shear modulus of the saturated rock, μ_{Sat} as predicted by the Biot-Gassman theory (Greenberg and Castagna 1992). terms of the bulk and shear moduli as:

$$M = K + {}^{4\mu}/_{3}, \quad (10)$$

and the Lame's first parameter (λ)) is estimated as:

$$\lambda = K - {}^{2\mu}/_{3}. \quad (11)$$

The estimated compressional modulus and Lame's first parameters are plotted against depth in figures 4 and 5, respectively. The P-wave velocity is measured in the logged interval using Gassmann's (1951) relation as:

$$V_P = ((K + \tfrac{4}{3}\mu)/\rho_b)^{\frac{1}{2}} \quad (12)$$

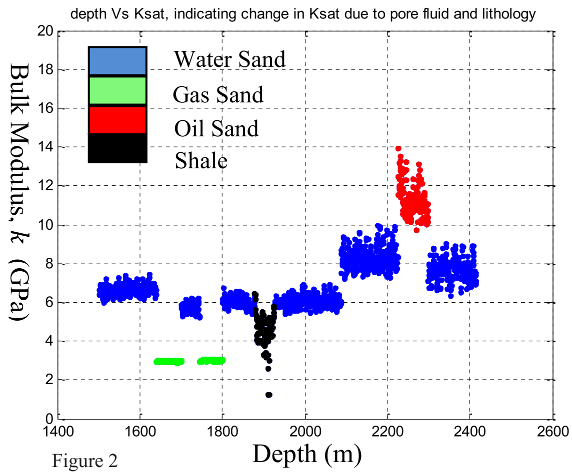


Figure 2

Figure 2: (left). The estimated bulk modulus versus depth- showing sensitivity of the bulk modulus to different fluids in the rocks in logged interval. Bulk modulus is also sensitive to changes in lithology. It registers different values for water saturated sand and water saturated shale.

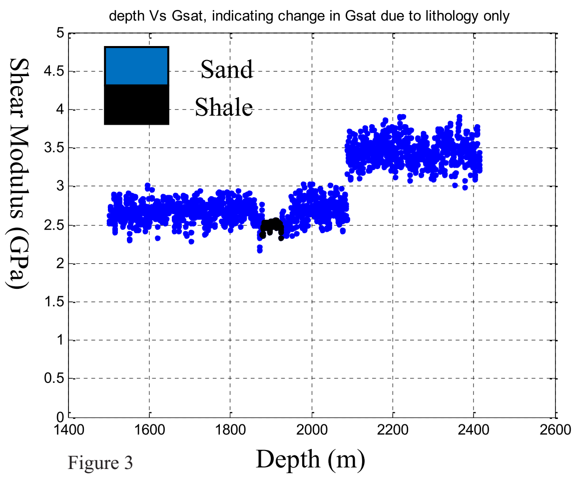


Figure 3

Figure 3: (right). The estimated shear modulus versus depth. Shear modulus is not sensitive to pore fluid but sensitive to change of lithology (sand – shale – sand) due to the changes in mineral matrix.

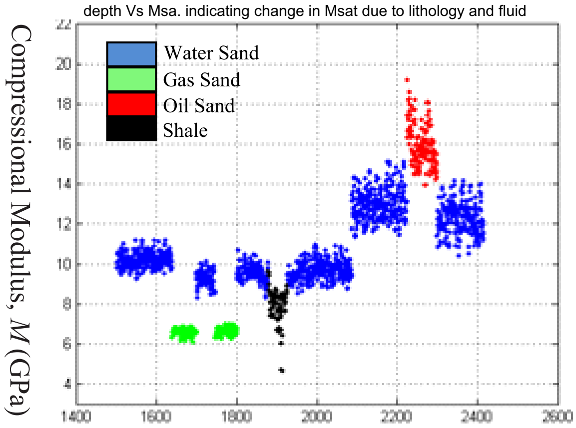


Figure 4 Depth (m)

Figure 4: Estimated compressional modulus versus depth in the logged interval. The plot shows the sensitivity of compressional modulus to different pore fluids and lithologies.

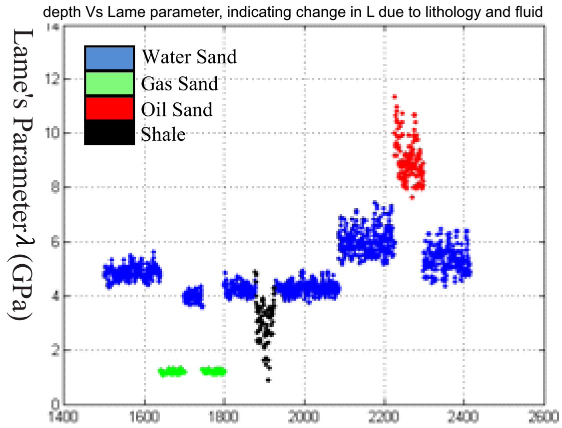


Figure 5 Depth (m)

Figure 5: Estimated Lame's first parameter versus depth. The plot shows the sensitivity of Lame's first parameter to change of pore fluid.

The shear wave velocity is estimated (Domenico 1976; Waters 1987) as:

$$V_S = (\mu/\rho_b)^{\frac{1}{2}} \tag{13}$$

Where the shear modulus of the rock (μ), bulk modulus of the saturated rock (K) and the bulk density (ρ_b) are from equations (9), (7) and (5) respectively. The shear modulus of a saturated rock is the same as the shear modulus of the dry rock ($\mu_{dry} = \mu_{sat}$). V_p and V_s are plotted against depth in figures 6 and 7, respectively. The estimated V_p / V_s for the logged depth is plotted in figure 8. It is important to note that sands in the interval between 2100m and 2416m are more compacted and less porous due to the weight of overburden material. The sand is probably over-pressured and if compared to the shallow sand, would exhibit slightly different properties including density and velocity, even if they contain the same fluid. This probably explains the observed increase in the values of velocity and elastic moduli in deep sand relative to the shallow sand.

Inverse – Q Analysis in Well Logs

In the seismic frequency range, the oscillatory fluid flow between the soft and the stiff parts of the rock induced by the passing seismic waves is responsible for velocity-

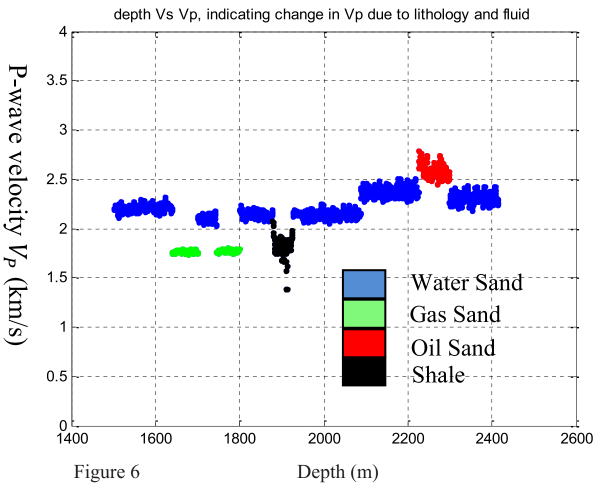


Figure 6: The estimated P-wave velocity versus depth in the logged interval. P-wave velocity is sensitive to change of pore fluid and lithology.

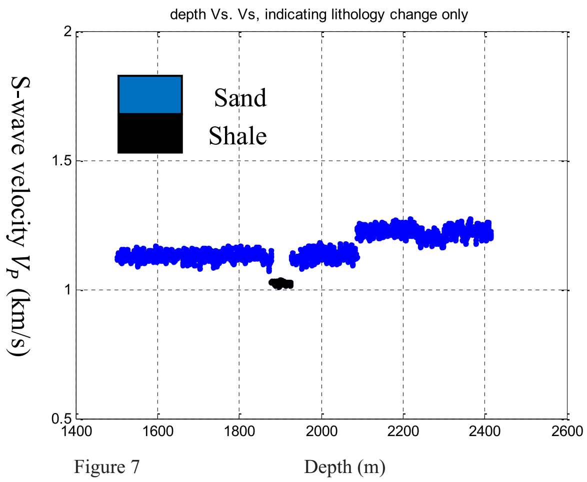


Figure 7: Estimated S-wave velocity versus depth in the logged interval. S-wave velocity is not sensitive to change of pore fluid, but sensitive to change of lithology.

frequency-dispersion and attenuation. At low frequency, the soft and stiff parts of the rock are in hydraulic communication (Mavko and Dvorkin 2005), and the theory of pore-scale fluid distribution applies. The bulk modulus of the saturating fluid is the harmonic average of the bulk modulus of the individual fluid present in the rock. The compressional modulus of the partially saturated rock is estimated using the model of Gassmann (1951) or Mavko *et al.* (1995). At high frequency, the concept of pore-scale fluid distribution is not applicable. Fluid distribution is assumed to be at the patch-scale. The compressional modulus of the different (homogenous) regions of the rock is estimated individually using the

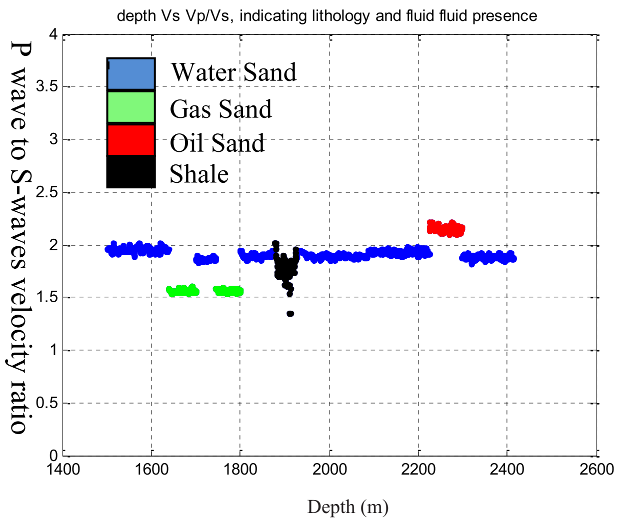


Figure 8: Estimated P-wave to S-waves velocity ratio versus depth in the logged interval. The velocity ratio discriminates between pore fluids. It is also sensitive to the change of lithology.

bulk modulus of the fluid in the region. The compressional modulus of the entire rock is estimated as the harmonic average of the individual homogenous regions in the rock (Gassmann 1951; Mavko *et al.* 1995). The high frequency modulus is usually larger than the low frequency modulus: the difference between the high and low frequency compressional moduli is translated into the inverse quality factor (Q^{-1}) using the heterogeneous Q model (Dvorkin and Uden 2004; Dvorkin and Mavko 2006). The heterogeneous Q model states that the changes in rock moduli can be linked to attenuation by the Krammer-Kronig relation and the standard linear solid model (Mavko *et al.* 1998) as:

$$Q^{-1}_{max} = \frac{M_H - M_L}{2\sqrt{M_L M_H}}, \qquad (14)$$

where M_H and M_L are the high frequency compressional modulus and low frequency compressional modulus, respectively. The high and low frequency moduli are determined based on the 'relaxation' and 'unrelaxation' of the patches in the rock due to the propagation of the waves.

Viscoelastic theory such as the one described in equation (14) allows the estimation of the inverse Q (Q^{-1}) from basic parameters that are readily available from borehole data and laboratory measurements. The effect of the change of fluid, or variation in the saturation level of the rock can be estimated from the rock properties obtained from well log data and the geological information about mineral composition using the rock physics anelastic formulation of Duffaut *et al.* (2001). Attenuation is estimated from well data using the model defined in equation (14). The model can be used to explain two physical processes that result in seismic wave attenuation. The first process is the movement of fluids with low compressibility (e.g. water) into and out of spaces occupied by more compressible fluids (e.g. gas) due the pressure difference created by the passage of seismic waves. This process assumes that the patchy saturation model (Mavko *et al.* 1998) accurately describes the volumetric disposition of fluids with different compressibilities. The second process is the movement of fluid from a more compressible rock to a more rigid rock with the passage of seismic waves. For an example, if a soft shale overlies a rigid sand, the non-bound fluid will move out of the shale, and into the sand as the compressional wave-front passes and then reverses itself in the tensional portion of the wave-front (Singleton 2008).

These two processes cause attenuation because part of the energy of the passing wave is irreversibly converted into heat due to the movement of fluid in and out of the confined rock pore structure. The rock moduli at high and low frequencies are estimated from the log data as:

$$M_H = \left(\frac{S_W}{M_p} + \frac{h_c}{M_{SW=0}}\right)^{1/2}, \tag{15}$$

$$M_L = M_s \frac{\emptyset M_{DRY} - (1+\emptyset) K_F M_{DRY}/M_S + K_F}{(1-\emptyset) K_F + \emptyset M_S - K_F M_{DRY}/M_S}, \tag{16}$$

where M_S is the compressional modulus of the rock grain matrix (i.e. minerals), M_{Dry} is the compressional modulus of the dry rock, K_F is the bulk modulus of the fluid, and θ is the porosity. M_P and $M_{SW=0}$ are the moduli of water saturated and hydrocarbon saturated regions, respectively. Mathematical definitions of M_P, $M_{SW=0}$, and other parameters are given in the appendix. Similar to equation 14, P-wave attenuation (Q_P^{-1}) and S wave attenuation (Q_S^{-1}) can be estimated as:

$$Q_P^{-1} = \frac{M_H - M_L}{2\sqrt{M_L M_H}}, \tag{17}$$

$$Q_S^{-1} = \frac{\mu_H - \mu_L}{2\sqrt{\mu_L \mu_H}}, \tag{18}$$

where μ is the shear modulus, M is the compressional modulus, and subscript L and H represents the low frequency and high frequency components of the moduli, respectively. Because shear modulus is not sensitive to fluid, the theory of frequency velocity dispersion is not applicable. Therefore, the shear modulus of a rock at low and high frequencies are same. A relationship between the P-wave and S-wave inverse – Q in terms of the compressional (M) and shear (μ) modulus (Mavko and Dvorkin 2005) is:

$$\frac{Q_P^{-1}}{Q_S^{-1}} = \frac{1}{4}\frac{(M/\mu - 2)^2(3M/\mu - 2)}{(M/\mu - 1)(M/\mu)}, \tag{19}$$

where, $M = \sqrt{M_L M_H}$ and $\mu = \sqrt{\mu_L \mu_H}$.

The relationship defined in equation 19 is used to estimate S-wave inverse - Q. The estimated P- and S-wave inverse – Q (or P- and S-waves attenuation) are plotted in red colour in figure 9. The results show that the (Q_P^{-1}) signature is high in gas saturated sand and oil saturated sand, relative to the water saturated sand. As derived from the study, the (Q_S^{-1}) result at depth interval of 2200m – 2300m does not support theoretical prediction which says (Q_S^{-1}) is insensitive to fluid. The P- to S-wave inverse quality factor ratio, $\frac{Q_P^{-1}}{Q_S^{-1}}$ is also estimated for the logged interval and plotted against depth in figure 10. A cross plot of velocity ratio, $\frac{V_P}{V_S}$ and attenuation ratio, $\frac{Q_P^{-1}}{Q_S^{-1}}$ is shown in figure 11. Qualitative interpretation of the results plotted in figure 10 shows that: gas sand exhibits $\frac{Q_P^{-1}}{Q_S^{-1}}$ higher compared to water sand, while inverse – Q-velocity ratios chart. Gas sand is characterised by the highest $\frac{Q_P^{-1}}{Q_S^{-1}}$ and lowest $\frac{V_P}{V_S}$, while oil sand is characterized by the lowest $\frac{Q_P^{-1}}{Q_S^{-1}}$ and highest $\frac{V_P}{V_S}$. Water sand is characterized by $\frac{V_P}{V_S}$ and $\frac{Q_P^{-1}}{Q_S^{-1}}$ values that plot between those of gas and oil sands. These results are similar with the findings by Klimentos (1995) who measured P-wave and S-wave attenuation from full waveform sonic and dipole log data in medium porosity sandstone saturated with oil, water, gas and gas condensate. A plot from the results obtained by Klimentos (1995) is shown in figure 12. A similar result was also reported by Mavko *et al.* (2005) after analysing attenuation in a well from the Gulf of Mexico. Laboratory observations supporting the results shown in figures 10 and 11 include Murphy (1982) and Lucet (1989). The similarity in the V_P / V_S of water and oil in figure 11 may be attributed to the similarity in the viscosity and density of the fluids (Jones 1986).

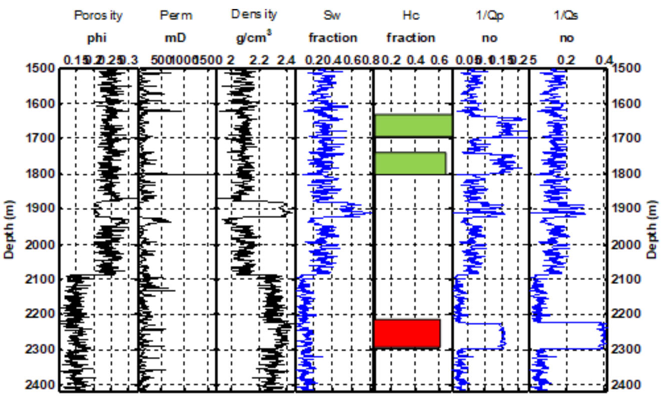
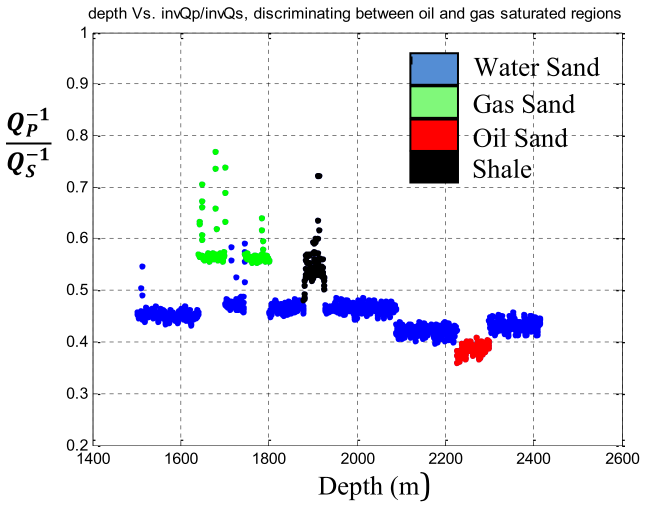


Figure 9: Attenuation log computed from well data with the predicted inverse quality factor (Q^{-1})) in the two last frames. From left to right: porosity, density, water saturation, hydrocarbon saturation (green is gas, red is oil), P-wave inverse quality factor and S-wave inverse quality factor.

DISCUSSION OF RESULTS

The sensitivity of the petro-elastic parameters (bulk, shear and compressional moduli, and the Lame's first parameters) to pore fluid are used to determine the presence of fluids in the rocks penetrated by well A-10 of the Gullfaks field. Similar to the P-wave velocity, the bulk modulus, compressional modulus, and the Lame's first parameter are sensitive to the presence and change of pore fluids. They are also sensitive to change of lithology. Similar to the S-wave, the shear modulus is not sensitive to the presence or change of fluid, but it is sensitive to the change of lithology. Results from the study show that bulk modulus can distinguish between different pore fluids. The values of bulk modulus are higher in water saturated sand than in gas saturated sand, but lower in comparison with oil saturated sand. The bulk modulus (K)) is also sensitive to the change in lithology arising from the shale break. The shear modulus is only sensitive to change of lithology, but insensitive to pore fluid. This result is consistent with the laboratory observations of Yuedong and Hongwei (2007). The λ and M parameters exhibit



fluid sensitivity in a similar way to K. Plots of V_P with depth show low P-velocities in gas sandstone (green) compared to water saturated sandstone (blue). For the basal sandstone, the oil saturated regions (red) exhibits high velocity compared to the water saturated region (blue). The V_P plot also indicates changes in rock mineral matrix, due to the change of lithology from sand to shale. V_S is not sensitive to rock fluids and does not distinguish between gas, water and oil, it only detects change in lithology due to the shale break. Results from V_P are similar to that of V_P. V_P / V_S detects change of pore fluid and lithology.

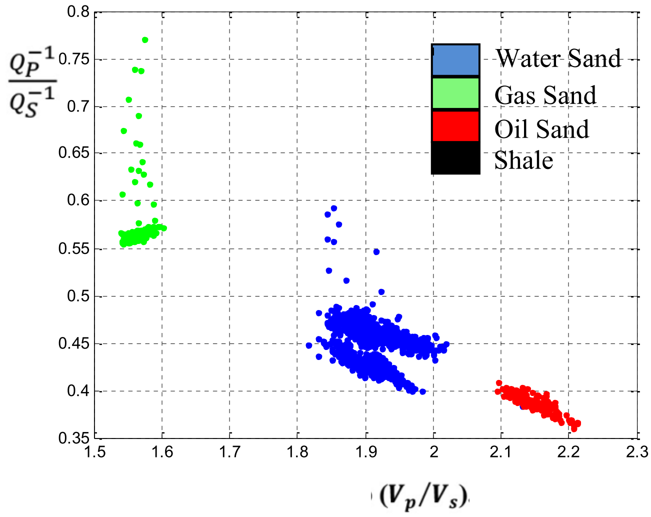


Figure 10: The estimated inverse quality factor ratio, Q_P^{-1} / Q_S^{-1} plotted with depth. Colour index is shown in the legend.

Figure 11. Cross plot of the ratio of the inverse quality f actor (Q_P^{-1} / Q_S^{-1}) and the velocity ratio (V_P / V_S).

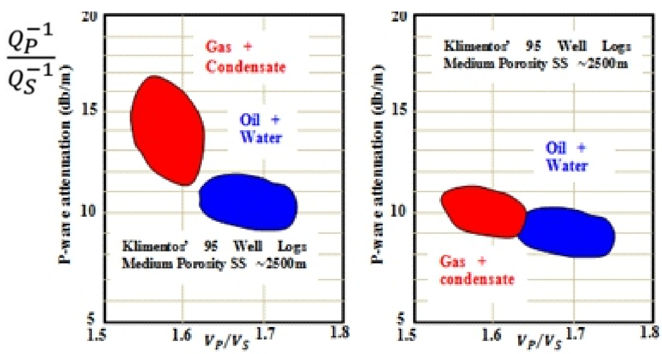


Figure 12: P-wave and S-wave attenuation calculated from full-waveform sonic and dipole log data in medium-porosity sandstone with oil, water, gas and condensate by Klimetos (1995). Adopted from Mavko *et al.* (2005)

Petro –elastic parameters computed from well data using rock-fluid physics formulations show that inverse–Q is sensitive to the fluid present in the pore spaces of rocks. P-wave inverse–Q distinguishes between water (brine) saturated sand and gas saturated sand. Inverse – Q is higher in hydrocarbon saturated intervals (up to 2.0 in some places) than in water saturated regions where the attenuation value is less than or equal to 0.1. The S-wave inverse–Q is sensitive to rock matrix but is generally insensitive to the pore fluid. High inverse–Q in shale interval (1874m – 1933m) may be attributed to the effect of lithologic heterogeneity (figure 10) since both sand and shale in the interval between 1800m and 2000m have their pore spaces saturated with the same kind of fluid (water). Stainsby and Worthington (1985) has previously reported high attenuation in the North Sea Shale. P-wave inverse quality factor ($1/Q_P$) is higher in gas sand than in water sand.

The S-wave inverse quality factor ($1/Q_S$) is high everywhere in the logged interval relative to the P wave inverse quality factor. $1/Q_S$ does not distinguish between water and gas, but registered different signatures for sand and shale. Higher value of $1/Q_S$ in the oil saturated sand compared to the gas and water saturated sands is at variance with theoretical predictions (Klimentos, 1990) which says $1/Q_S$ is insensitive to fluids. However, it may be speculated that the high signature of $1/Q_S$ in the oil sand is in response to high pressure and the change in the bulk density of the oil sand. A complete set of unrelated analyses will be required to better interpret the observed high $1/Q_S$ in the oil sand. Cross plots of P- to S-wave inverse quality factor, Q_P^{-1}/Q_S^{-1} and P- to S-wave velocity ratio (V_P / V_S) clearly distinguish gas sand from water sand, and water sand from oil sand. Therefore, attenuation attributes as well as its cross plot with elastic attributes can be used as hydrocarbon indicator and for reservoir characterisation. It is noted that basic well logs such as resistivity, Compressional sonic and Shear sonic logs are required for this kind of analysis. The emphasis of this study is in the qualitative results and not the absolute value of the results as they are derived from theoretical data.

CONCLUSIONS

A Combination of petro-elastic parameter (or elastic modulus) and P- and S-wave attenuation (inverse–Q) has been used to analyse the properties of the rocks penetrated by well A-10 of the Gullfaks field, North Sea, Norway. The petro-elastic parameters: Lame's first parameter, the bulk, and compressional moduli show comparable results: they are lower in gas saturated rock compared to water saturated rock; and higher in oil saturated rock compared to water saturated rock. Therefore, they can be potentially used to indicate a change of pore fluid. Hydrocarbon saturated zones exhibit higher P-wave inverse–Q than water saturated zones. For the case study, the derived range of $\frac{Q_P^{-1}}{Q_S^{-1}}$ values for gas, water, and oil saturated sands are 0.56 – 0.78, 0.39 – 0.55, 0.35 – 0.41, respectively. A cross plots of the ratio of the P- to S-waves inverse – Q and the P- to S-wave velocity ratio distinguished gas from water and water from oil. Attenuation analysis in wells can be used to compliment other methods (e.g., AVO), to mitigate exploration risk in the search for hydrocarbon accumulation,

Appendix

Table 1: Values of the parameter used in the computation of the Elastic Moduli.

Parameter	K_W	K_G	K_{Oil}	G_{Sat}	$G_{DrySand}$	$G_{DryShale}$
value	2.54	0.08	1.41	3.2	5.2	4.4

Parameter	ρ_{Water}	ρ_{Oil}	ρ_{Gas}	ρ_{Shale}	ρ_{Sand}	S
value	1.04	0.824	0.00077	2.85	2.68	4.4

Parameter	K_{Clay}	K_{Quartz}	M_{Clay}	G_{Clay}	ρ_{Sand}	G_{Quartz}
value	1.45	37.9	95.67	3.37	2.68	44.3

Parameter	ρ_{clay}	ρ_{Quartz}				
value	1.58	2.65				

Sources: Mavko *et al.* (1998), Duffaut. (2001), and Andersen *et al.* (2009).

Notations and Units: ρ represents density. The unit is in g/cm3. While *G* and *K* represents shear modulus and bulk modulus respectively. Their unit is Gpa (Giga Pascal)

Mathematical definitions of some elastic moduli

$$\frac{1}{K_F} = \frac{S_W}{K_W} + \frac{1-S_W}{K_G}\,;\; M_S = V_{Clay}M_{Clay} + (1 - V_{Caly})M_{Quartz};$$

$$M_{Dry} = M_s\,\frac{1-(1-\emptyset)M_{sat}/M_S-\emptyset M_{sat}/K_F}{1+\emptyset-\emptyset M_S/K_F-M_{Sat}/M_S};\;\; M_{Sat} = \rho V^2$$

$$M_P = M_s\,\frac{\emptyset M_{DRY}-(1+\emptyset)K_W M_{DRY}/M_S+K_W}{(1-\emptyset)K_W+\emptyset M_S-K_W M_{DRY}/M_S}\;;$$

$$M_{SW=O} = M_s\,\frac{\emptyset M_{DRY}-(1+\emptyset)K_G M_{DRY}/M_S+K_G}{(1-\emptyset)K_G+\emptyset M_S-K_G M_{DRY}/M_S}\;;$$

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