Fluid substitution in tight shale using the soft-porosity model
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Summary

We propose a methodology to conduct fluid substitution in low porosity and very low permeability shale (tight shale). Gassmann’s equations are often used to predict the change in the rock’s elastic properties when the pore space fluid is replaced with a second fluid. These equations assume that the wave-induced pore pressures are equilibrated throughout the pore space. When sonic P- and S-waves travel through extremely low permeability rocks, there is not enough time for the pore fluid to flow and remove wave-induced pore pressure gradients. Thus, to conduct fluid substitution in tight shales, a different methodology should be used. In this study we compare two different fluid substitution approaches, which correspond to two extreme fluid relaxation scenarios: (1) all pores, stiff and soft, are assumed to be disconnected. This is the least fluid relaxed scenario because there is no pore-to-pore equilibration of pore pressure. This scenario is implemented using an effective medium model with an idealized microstructure. (2) All pores are assumed to be connected. This scenario is implemented using Gassmann’s equations. This is the most relaxed scenario, with the highest degree of effective pore connectivity. This is the low frequency case where pore pressure can equilibrate.

We find that: (1) the greatest gas effect on P-wave velocity is obtained when using the soft-porosity model (SPM) with gas preferentially placed in the soft pore space. (2) The effect of gas when using Gassmann’s equations is about three times smaller than when using SPM. (3) The single aspect ratio model (SAR) produces results between Gassmann and SPM. (4) The values for $\phi_{SAR}$ and $\alpha_{SAR}$ found using SPM and SAR, respectively, are slightly different when determined from different fluid distributions, or when determined from $V_p$ or $V_s$. (5) The greatest gas effect on $V_s$ velocity is obtained when using the soft-porosity model. As Gassmann’s equations, SAR does not predict any variation on shear modulus.

Introduction

In tight rocks, if pores have high aspect ratios (rounded), the elastic moduli of the rock mineral matrix often dominates those of the bulk rock (Ruiz and Dvorkin, 2010b), but if the rock has low aspect ratio pores (crack like pores), this is not necessarily true. This is because in shales the tight rock matrix (solid phase) may be considered a composite and may include constituents with vastly different moduli and shapes, such as clay and kerogen grains which have low elastic moduli and low grain aspect ratios (flaky grains), as well as quartz or pyrite grains (rounded grains) which have high elastic moduli and high aspect ratios. Thus, the effective solid matrix elastic moduli in this type of rock may or may not dominate those of the bulk rock. The magnitude of fluid effect on elastic properties depends on the elastic moduli contrast among solid and fluid constituents and on the volumetric fractions and aspect ratios of stiff solid grains (e.g. rounded quartz and pyrite), soft solid grains (e.g. clay and kerogen), stiff pores, and soft pores (e.g. fractures). In this study, we consider P- and S- sonic waves at well-log scale travelling in the vertical direction through tight shale containing stiff- and soft pores (e.g. fractures). We assume that solid grains and pores are randomly orientated and randomly distributed in position, and that P- and S-sonic wavelengths (~3 ft) are much greater than soft- (e.g. fractures) and stiff-pores dimensions.

The goal of this study is to estimate the change in tight shale elastic properties when the pore space fluid is replaced with a second fluid (e.g. brine with gas). Gassmann’s equations (Gassmann, 1951) are often used to account for these changes. However, these equations assume that the wave-induced pore pressures are equilibrated throughout the pore space, which is not true in tight shale. Thus, to conduct fluid substitution in tight shales, we propose the use of effective medium models. The results of using effective medium models are compared with those from using Gassmann. These two fluid substitution approaches correspond to two extreme fluid relaxation scenarios. In scenario 1, all pores, stiff and soft, are assumed to be disconnected (Figure 1, left). This is the least fluid relaxed scenario because there is no pore-to-pore equilibration of pore pressure. In scenario 2, all pores are connected (Figure 1, right). This is the most relaxed scenario, with the highest degree of effective pore connectivity. This is the low frequency case where pore pressure can equilibrate. The realization of each of these two scenarios is through creating or eliminating pore-to-pore connections or changing the period of the applied stresses to be faster or slower than the pore-to-pore diffusion times. The connotation of high and low frequency here is that the connectivity is effectively controlled by the diffusion time versus frequency (Mavko and Jizba, 1991; Ruiz and Dvorkin, 2009). The effective medium approaches assume idealized rock microstructures. In this study we specifically chose two different effective medium models: the soft porosity model (SPM) (Ruiz and Cheng, 2010c) and the single aspect ratio model (SAR) (Ruiz and Dvorkin, 2010a). SPM divides the rock total porosity...
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(ϕ_{total}), into two spaces: the stiff-pore space (stiff-porosity) and the soft-pore space (soft-porosity). The soft-porosity (ϕ_{soft}) and stiff porosity (ϕ_{stiff}) are defined as the volumetric fraction of inclusions of aspect ratio 0.01 (i.e. cracks) and spheres of aspect ratio 1, respectively. In SAR, it is assumed that all pores have the same aspect ratio. The results from these approaches are compared with those using Gassmann. The substitution is achieved by placing different fluids in different parts of the pore spaces (soft and stiff) or by filling both pore spaces with a single effective fluid. The P-wave velocity depends strongly on the pore fluid bulk modulus in the most compliant pores (low aspect ratio).

![Figure 1](image.png)

Figure 1. Left: hydraulic disconnected pores and fractures, least relaxed scenario, implemented using effective medium models. Right: hydraulic connected pores and fractures, most relaxed scenario, implemented using Gassmann’s equations.

In different scenarios, fluids (S_{s} and S_{u}) can be distributed in different ways within the soft- and stiff-pores (ϕ_{soft} and ϕ_{stiff}). We test two of these possible fluid distribution scenarios. The first consists of saturating the soft- and stiff pore space at all depth locations with a fluid mixture of 80% gas (S_{s}) and 20% brine (S_{u}) having an effective fluid bulk modulus k_{f} (the harmonic average of k_{w} and k_{s}). The second scenario consists of preferentially filling the soft pores with gas and the stiff pores with brine. In an in situ case, we often have two different volumes, hydrocarbon (S_{g}) and brine (S_{w}), distributed in two pore spaces, soft porosity (ϕ_{soft}) and stiff-porosity (ϕ_{stiff}). Preferentially filling soft-pores with gas means that the soft pores are first filled with the estimated gas saturation, and then the remaining pores (soft- and stiff) are filled with brine. The soft porosity (or fracture porosity) is always very small compared to the total porosity, so if the soft pores are filled with the estimated gas saturation first, all soft pores and also some stiff pores will be filled with gas.

We also implement scenario 1 using the single aspect ratio SAR pore structure. However, we consider that even though SAR is a good V_{s} predictor, it is based on a microstructure that is not consistent with the tight shale microstructure.

Several assumptions were made in this research. In tight shale, part of the gas is stored as free gas in fractures and matrix porosity, and part is adsorbed onto organic material and shale particle walls. However, because of lack of quantitative information about adsorbed gas volume, for this modeling we treated all gas as free gas and thus able to move inside of and between pores. We also did not have data regarding fractures with dimensions greater than well log resolution, so only the effect of microfractures (soft-pores) was considered. Finally, we also did not consider variation of clay and kerogen particle aspect ratios and specific orientations in the modeling. All of these issues will be treated in future research as data becomes available.

Comparison of fluid substitution approaches using SPM, SAR, and Gassmann: Barnett shale example

To apply SPM and SAR, we need to assume specific distributions of fluids in the pore space. These two approaches assume that one of the velocities, V_{p} or V_{s}, is not available, so the process of finding ϕ_{soft} and α_{SAR} also provides the unavailable velocity. When V_{s} is not available, fluid substitution may be accurately conducted by using Mavko-Gassmann’s equation (Mavko et al., 1995). However, if Poisson’s ratio is needed for seismic interpretation, another alternative procedure is inputting the theoretical estimated V_{s} into Gassmann’s equation instead of using Mavko-Gassmann’s equation.

We tested two hypothetical saturation conditions: (1) rocks fully saturated with brine and (2) rocks saturated with a mixture of 80% gas (S_{s}) and 20% brine (S_{w}). Figures 2-4 show the results of conducting fluid substitution in the upper part of the lower Barnett shale formation. This shale interval can be divided into two smaller intervals, the upper shows high TOC and high gas saturation and the lower shows low TOC and is fully brine saturated.

Figure 2 shows the results of conducting fluid substitution in four different ways: (a) Gassmann’s equations, (b) SPM based on V_{p}, filling the pore space with a 80% gas and 20% brine mixture (SPM-Mix-P), (c) SPM based on V_{s}, placing the gas fraction preferentially in the soft pore space (SPM-Gas-P), and (d) SAR based on V_{s}, filling the pore
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space with a 80% gas and 20% brine mixture (SAR-Mix-P). The greatest gas effect on \( V_p \) is obtained when using the soft-porosity model with gas preferentially placed in the soft pore space. The effect of gas when using Gassmann’s equations is about three times smaller than the effect when using SPM. SAR produces results that are between Gassmann and SPM. If instead of gas we use a 80% gas/20% brine mixture in all pores (stiff and soft), the results are almost the same because the mixture compressibility is as small as gas compressibility. Figure 3 shows the aspect ratio curve \( (\alpha_{SAR}(z)) \) obtained from SAR-Mix-P and the soft porosities curves \( (\phi_{soft}(z)) \) obtained from SPM-Mix-P, SPM-Mix-S, SPM-GAS-P and SPM-GAS-S. The \( \phi_{soft} \) and \( \alpha_{SAR} \) found using SPM or SAR, respectively, are slightly different when determined from different distribution of fluids or when determined from \( V_p \) or from \( V_s \).

The greatest gas effect on \( V_s \) is obtained when using the soft-porosity model. As Gassmann’s equations, SAR does not predict any variation on shear modulus. (Figure 4).

Conclusions

1. The greatest gas effect on \( P \)-wave velocity is obtained when using the soft-porosity model with gas preferentially placed in the soft pore space. (2) The effect of gas when using Gassmann’s equations is about three times smaller than when using SPM. (3) SAR produce results between Gassmann and the soft porosity model. (4) The \( \phi_{soft} \) and \( \alpha_{SAR} \) found using SPM or SAR, respectively, are slightly different when determined from different fluid distributions or when determined from \( V_p \) or from \( V_s \). This small difference is enough to largely amplify the effect of gas on elastic properties of tight gas shale. (5) The greatest gas effect on \( V_s \) is obtained when using the soft-porosity model. As Gassmann’s equations, SAR does not predict any variation on shear modulus.

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Figure 2. From left to right: Volumetric fractions of minerals, TOC, and fluids; fluid substitution using Gassmann equation; fluid substitution using Mavko-Gassmann equation; fluid substitution using SAR-MIX-P; and fluid substitution using SPM-MIX-P.

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Figure 3. From left to right: volumetric fractions of minerals, TOC, and fluids; aspect ratio ($\alpha_{\text{SAR}}$) from SAR-MIX-P; soft porosity from SPM-MIX-S (based on $V_s$); soft porosity from SPM-GAS-P; and soft porosity from SPM-GAS-S (based on $V_s$).

Figure 4. From left to right: Volumetric fractions of minerals, TOC, and fluids; and fluid substitution using: single aspect ratio model (SAR-MIX-P); and soft porosity (SPM-MIX-P).
EDITED REFERENCES
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