Z-99 Attenuation at Patchy Saturation – A Model

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Summary. Wave-induced variations of pore pressure in a partially-saturated reservoir result in oscillatory liquid flow. The viscous losses during this flow are responsible for wave attenuation. The same viscous effects determine the changes in the dynamic bulk modulus of the system versus frequency. These changes are necessarily linked to attenuation via the causality condition. We analytically quantify the frequency dependence of the bulk modulus of a partially saturated rock by assuming that saturation is patchy and then link these changes to the inverse quality factor. As a result, the P-wave attenuation is quantitatively linked to saturation and thus can serve as a saturation indicator.

Physics of Patchy Saturation. The frequency range of seismic radiation used for illuminating the subsurface spans four orders of magnitude, from 10^1 (seismic) to 10^4 (sonic logging) Hz. Typically, the pore-scale Biot's and squirt flow attenuation mechanisms are not engaged at these frequencies. Still, viscoelastic effects and attenuation may arise from the oscillatory liquid cross-flow between fully-liquid-saturated patches and the surrounding rock with gas. The main condition for fluid-related attenuation in the practical frequency range is the existence of such patches whose length scale is several orders of magnitude larger than the pore scale.

To understand physical reasons for the existence of patchy saturation, let us consider a volume of rock that consists of several sand patches with clay content slightly varying among them. These clay-content variations may have a small effect on the dry-frame elastic moduli but dramatically affect permeability and, therefore, capillary pressure curves. Then, in a state of capillary equilibrium, this elastically homogeneous volume may have a patchy saturation pattern. Indeed, if capillary pressure is the same for the adjacent patches whose capillary pressure curves are different, these patches can have very different fluid saturation. Visual proof that patches form in oil-water and air-water systems in the laboratory has been presented by Chatenever and Calhoun (1952) and Cadoret (1993). Indirect evidence that patches exist in situ has been presented by Brie et al. (1995) and Dvorkin et al. (1999).

The size L of a continuous patch occupied solely by the liquid phase determines the effective bulk modulus of the partially saturated rock at a fixed global saturation and frequency. If the patch is small so that, $L < \sqrt{D/f}$ ($D = kK_W / \phi\mu$ is the diffusivity; k is the permeability; K_W is the bulk modulus of the liquid; ϕ is the porosity; and μ is the dynamic viscosity of the liquid), or the frequency is small, the wave-induced pore pressure variations between the patch and surrounding gas-saturated rock equilibrate during the wave period. The patch is *relaxed*. It appears that the critical size L of the patch may be as small as 10 cm at a frequency of 50 Hz. This length is approximately the scale of heterogeneity in the reservoir required for viscoelastic effects and attenuation to become detectable at seismic frequency. If the patch is large, $L > \sqrt{D/f}$, or the frequency is high, the wave-induced pore pressure variations in it will not equilibrate with the surrounding dry region during the wave period. The patch in *unrelaxed*. At the same saturation, the effective bulk modulus of the system with unrelaxed patches $K_{Sat\infty}$ will be larger than that of the same system with relaxed patches

K_{Sat0}. If the size of the patch is fixed and the frequency is changing, the effective bulk modulus of partially saturated rock will vary between its low-frequency limit K_{Sat0} and high-frequency limit $K_{Sat\infty}$.

Modulus-Frequency Dispersion and Attenuation. The difference between the elastic moduli calculated using the homogeneous and patchy saturation equations is, in essence, the difference between the low-frequency and high-frequency values of the elastic moduli. The effect of the apparent elastic moduli increase with increasing frequency is called the modulus-frequency dispersion (or the velocity-frequency dispersion, if we consider the elastic-wave velocity instead of the elastic moduli). Let us reiterate that here we examine the modulus-frequency dispersion in the practical frequency range that includes seismic and sonic frequencies. As a result, we do not consider the ultrasonic frequency dispersion effects related to the microscopic squirt flow and the Biot mechanisms.

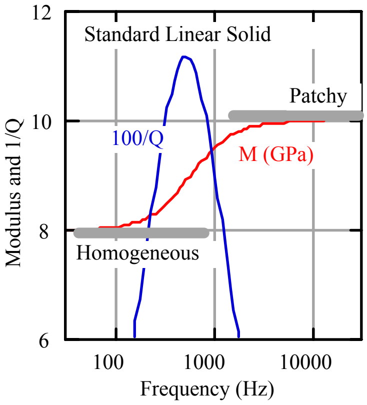

Figure 1. The compressional modulus and inverse quality factor versus frequency for the low-frequency modulus value 8 GPa and high-frequency modulus value 10 GPa.

The transition between the lower (homogeneous saturation) bulk modulus value and the upper (patchy) bulk modulus value can be interpreted in fact as the transition between the low and high frequency. The corresponding elastic modulus dispersion is necessarily accompanied by absorption, according to the Kramer-Kronig relation for linear viscoelastic systems. To quantify this absorption, we need to identify the frequency variation range (e.g., the low-frequency limit is at 10 Hz and the high-frequency limit is at 10 kHz) and also to know *how* the elastic modulus evolves as it changes between its low-frequency and its high-frequency values. In other words, we have to select a viscoelastic model. One such model is the standard elastic solid model. According to this model, the maximum inverse quality factor depends on the difference between the low-frequency compressional modulus M_0 and the high-frequency compressional modulus M_∞ (the compressional modulus is the bulk modulus plus four-third of the shear modulus): $Q_{\max}^{-1} = 0.5(M_\infty - M_0)/\sqrt{M_0 M_\infty}$. Figure 1 shows how the compressional modulus of a partially saturated rock varies between its low-frequency and high-frequency value and how the inverse quality factor varies in accordance with this modulus-frequency dispersion.

Application to Well Log Data. We used the above-described approach of calculating the inverse quality factor in a gas well. The inverse quality factor at partial saturation was added to the background value calculated at 100% water saturation according to the empirical relation of Koesoemadinata and McMechan (2001). The resulting attenuation is maximum in gas saturated intervals, especially where gas saturation is small. This fact means that anomalous attenuation may serve as an indicator of non-productive gas intervals (“fizz water”).

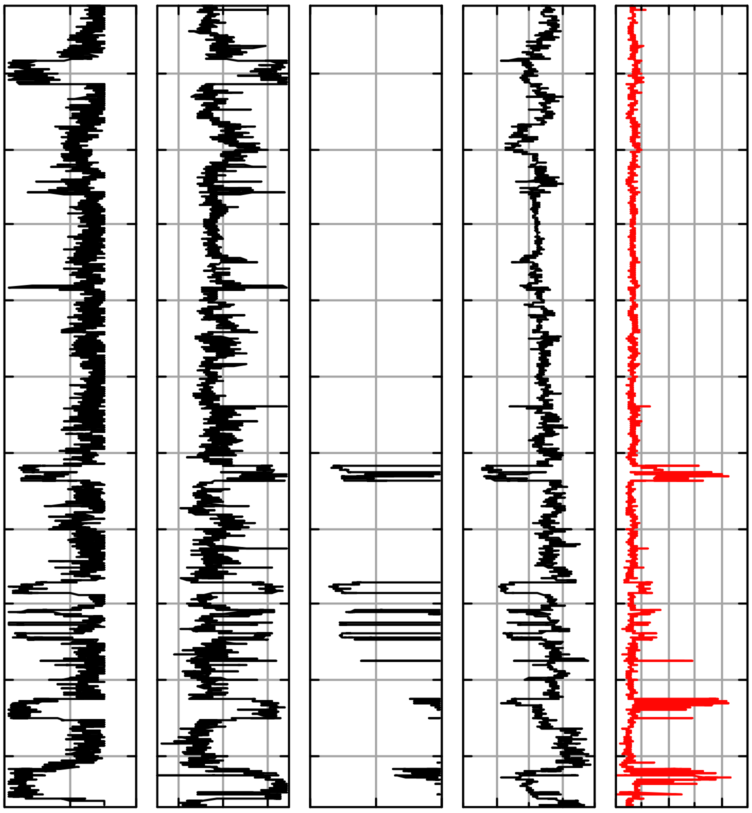

Figure 2. Clay content, total porosity, water saturation, P-wave velocity, and calculated inverse quality factor in a gas well. Displayed depth is fictitious but the scale is real.

Verification by Seismic Data. There are essentially no experimental data that could be used to directly verify our attenuation model at a well. Currently, the only feasible way is to calculate attenuation from seismic data at the well location and then compare it to our theoretical well log based predictions. Figure 3 illustrates such an attempt. Attenuation at the well location was estimated from seismic data using the anomalous absorption method developed by Rock Solid Images which is based on comparing the background attenuation trend to local variations. The seismic attenuation results match our model predictions based on well log data in the upper "fizz water" zone. It does not show the high attenuation predicted in the lower "fizz water" zones. An apparent reason is that water saturation in these lower zones was misinterpreted and they in fact contain no gas.

We conclude that the theoretical model introduced here is reasonably accurate and can be used to predict attenuation from well log curves as well as produce forward-modeling scenarios for synthetic seismic modeling that takes attenuation into consideration.

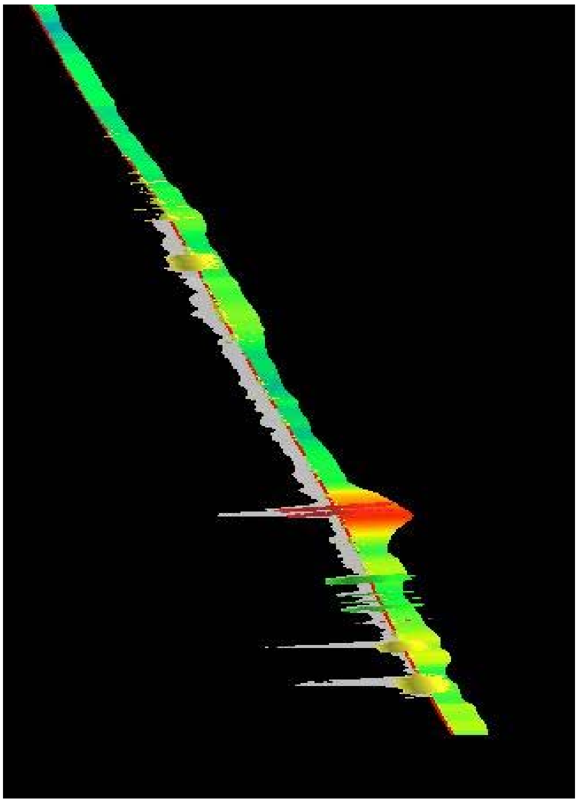

Figure 3. Attenuation at the well used in the example shown in Figure 2. Gray zone on the left-hand side of the well is for the inverse quality factor predicted from well log curves according to our theoretical model. The values increase to the left. The red-green zone on the right-hand side of the well is attenuation calculated from seismic data. Hot color means large attenuation. Seismic attenuation matches model prediction in the upper "fizz water" interval.

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