Can gas sand have a large Poisson's ratio?

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Summary

Laboratory data supported by granular-medium and inclusion theories indicate that Poisson's ratio in gas-saturated sand lies within a zero to 0.25 range, with typical values about 0.15. However, some well log measurements, especially in slow gas formations, persistently produce a Poisson's ratio as large as 0.3. If the latter is not due to poor quality data or anisotropy, two in-situ scenarios -- patchy saturation and sub-resolution thin layering -- provide a plausible explanation. In the first case, the well data have to be corrected to produce realistic synthetic seismic traces. In the second case, the effect may persist at the seismic scale.

Introduction: Significance of Poisson's Ratio

The Poisson's ratio (PR) of an isotropic solid is an element in a pair of independent elastic constants. It can be calculated from any other pair, such as bulk and shear moduli or the two Lame's constants. It can also be calculated from the P- and S-wave elastic-wave velocity which are routinely measured in the laboratory and/or well. One may find it is more convenient to use PR rather than the velocity ratio simply because the former is contained between zero and 0.5 while the latter may span the range between the square root of 2 and infinity. The importance of PR in exploration stems from the fact that it explicitly affects the amplitude-versus-offset (AVO) response of the reservoir – one of the simplest approximations to the Zoeppritz equations (Hilterman, 1989) states that the P-to-P reflectivity at an angle is directly proportional to the PR contrast between the upper and lower elastic half-space.

Consider an interface between hypothetical shale and gas sand layers where the total porosity is 30% in the shale and 25% in the sand. The clay content is 90% in the shale and 10% in the sand. The shale is filled with brine whose bulk modulus is 2.75 GPa and density is 1.02 g/cc. The sand has 30% water saturation with the rest of the pore space filled with gas whose bulk modulus is 0.07 GPa and whose density is 0.21 g/cc. The uncemented-sand model (Dvorkin and Nur, 1996) gives the following values for the P- and S-wave velocity and bulk density: 2.16 km/s, 0.87 km/s, and 2.12 g/cc, respectively, in the shale and 2.36 km/s, 1.56 km/s, and 2.15 g/cc, respectively, in the sand. Poisson's ratio is 0.404 in the shale and 0.113 in the sand. The P-to-P and P-to-S reflectivities versus the angle of incidence according to the Zoeppritz (1919) equations are shown in Figure 1.

Let us assume next that the S-wave velocity measured in the sand is (e.g., erroneously) only 80% of that given above, i.e., 1.25 km/s. The corresponding PR in the sand is 0.306. The respective reflectivities (as shown in Figure 1) are significantly different from those obtained using the original elastic parameters. If the S-wave velocity in the sand is further reduced and is now only 70% of the original value, i.e., 1.09 km/s, the respective PR in the sand becomes 0.364 and the reflectivity curves even further deviate from the original. This example shows the importance of PR measured in the well if it is used as a calibration input for seismic interpretation and reconnaissance.

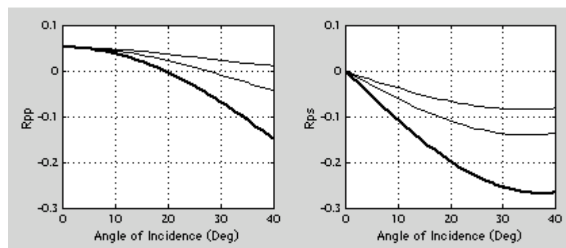

Figure 1. P-to-P (left) and P-to-S (right) reflectivity versus the angle of incidence at a shale/gas sand interface (example in the text). The bold curves are for the original case where the Poisson's ratio in the sand is 0.113. The uppermost curves are for the extreme case where the Poisson's ratio in the sand is 0.364. The curves in the middle are for the case where the Poisson's ratio in the sand is 0.306.

Problem Formulation

Figures 2 and 3 display laboratory velocity and Poisson's ratio data in over 150 room-dry sand and sandstone samples. Porosity, mineralogy, and velocity in these datasets span wide ranges. Yet, in spite of this tremendous variability, the Poisson's ratio measured on room-dry (air-saturated) sand samples, rarely exceeds 0.2. The same is true for dry glass-bead packs in a range of differential pressure between zero and 40 MPa – the measured Poisson's ratio is essentially contained between 0.1 and 0.2 (Figure 4).

These examples confirm an earlier finding by Spencer et al. (1994) that the range of Poisson's ratio in dry unconsolidated sands is from 0.115 to 0.237 with mean 0.187. This result is based on an extensive laboratory dataset that included natural sediment as well as artificial grain packs. Poisson's ratio is small independent of the type of the grain material (pure quartz, quartz with clay, corundum, garnet, diamond, calcite, or magnetite).

Theoretical calculations of the elastic moduli in dry packs of elastic particles according to various contact theories as well as in solids with inclusions (e.g., using the Differential Effective Medium theory) also indicate that PR in such systems should remain small.

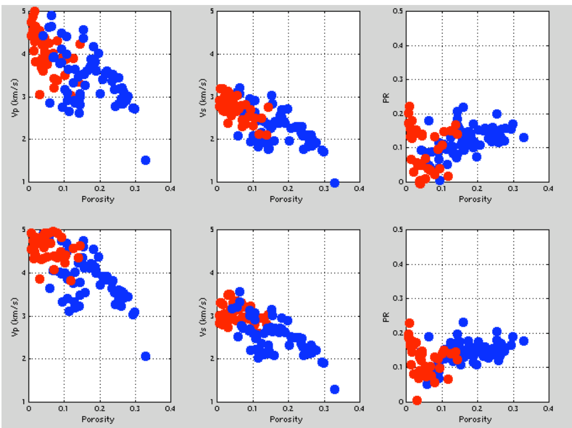

Figure 2. Laboratory velocity and PR data for consolidated sandstone samples at 10 (top) and 40 MPa (bottom) differential pressure. The samples are room-dry. The color indicates the source of the data – blue for Han (1986) and red for Jizba (1991). The clay content in these samples varies between zero and 50%. The high-porosity low-velocity data point that lies separate from other data is for clean Ottawa sand.

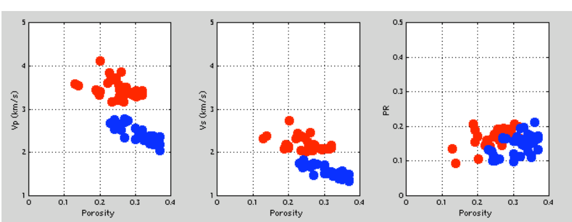

Figure 3. Laboratory velocity and PR data for dry clean unconsolidated sand samples at 30 MPa differential pressure. The samples are room-dry. The color indicates the source of the data – red for Strandenes (1991) and blue for Blangy (1992).

Based on these results, one may expect that PR measured in the well in gas sand should remain small. The problem as we see it is the apparent inconsistency of PR as calculated from the sonic and dipole velocity data in gas sand intervals: some results indicate that PR in such formations can be as small as 0.1 and certainly does not exceed 0.2 (Figure 5). Other measurements (Figure 6) produce PR in gas sand as large as 0.3.

The question we pose here is whether such data should be dismissed as erroneous or taken into account during well-to-seismic tie and synthetic seismic generation. In other words, are there situations that may produce relatively high PR in gas sand and still be consistent with the existing experimental evidence?

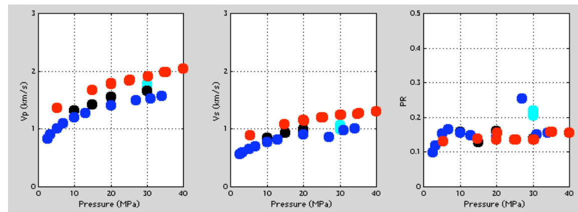

Figure 4. Laboratory velocity and PR data for dry glass-bead packs. The color indicates the source of data – blue for Winkler (1979); black for Yin (1992); cyan for Estes (1994); and red for Tutuncu (1995).

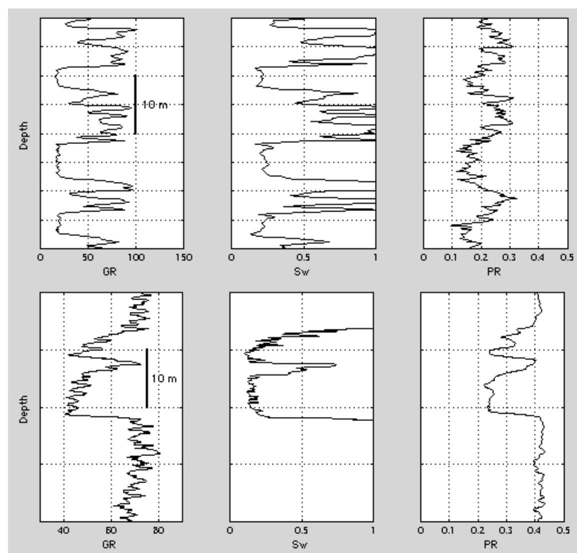

Figure 5. Well data in two different wells showing small PR (< 0.25) in gas sand.

Situation 1: Patchy Saturation

Consider unconsolidated sand with 30% porosity and 5% clay content filled with gas whose bulk modulus is 0.07 GPa and whose density is 0.21 g/cc and brine whose bulk modulus is 2.75 GPa and density is 1.02 g/cc. We calculate the elastic constants of the dry frame according to the uncemented-sand model (Dvorkin and Nur, 1996) and assume that the bulk modulus of the pore fluid at partial saturation is the harmonic average of those of the gas and brine. The resulting PR is plotted versus water saturation in Figure 7. Its end-member values are about 0.15 at zero water saturation and 0.40 at full water saturation. The transition between these two values is highly nonlinear: PR remains small between zero and 90% water saturation and exceeds 0.25 only as in the remaining saturation interval.

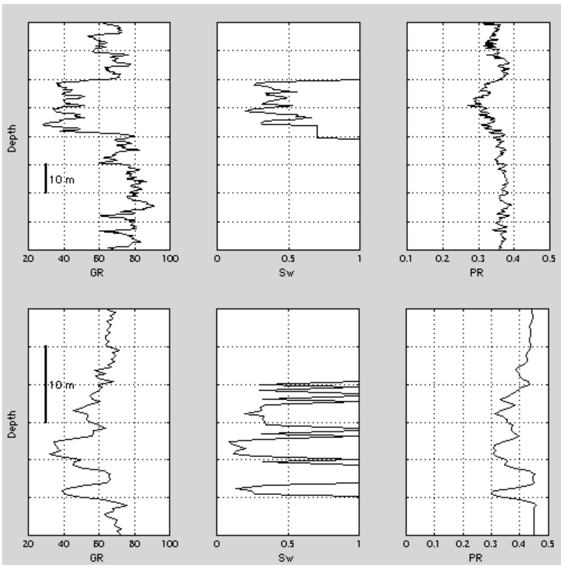

Figure 6. Well data in two different wells showing large (about 0.3) PR in gas sand.

A different way of treating the same problem would be to assume that the saturation pattern in the sand is *patchy* rather than *uniform*. In this case the notion of the effective pore fluid is no longer valid. Instead, we have to calculate the effective elastic moduli of a heterogeneous elastic material, parts of which are fully water saturated while other parts contain only gas. The effective compressional modulus of such patchy material whose shear modulus is uniform in space is the harmonic average of the compressional moduli of the patches (e.g., Dvorkin and Nur, 1998). The resulting PR is plotted versus water saturation in Figure 7. Its behavior is very different from that of PR at uniform saturation: it may exceed 0.25 at water saturation as small as 35% and remain high afterwards.

We see that patchiness in saturation may explain high PR observed in gas wells. It still remains necessary to explain whether and why such situations may occur in-situ. One possibility of such occurrence is discussed in Knight et al. (1998). It is attributed to a *transient* process of drainage or imbibition where slight spatial heterogeneity in capillary pressure results in the development of patches at partial saturation. Such a transient process in a well may be due to partial mud filtrate invasion. We do not expect saturation patchiness to exist in virgin formation undisturbed by filtrate invasion. *Therefore, high PR measured at a well due to partial mud filtrate invasion has to be corrected to ascertain the seismic response of virgin formation away from well control.*

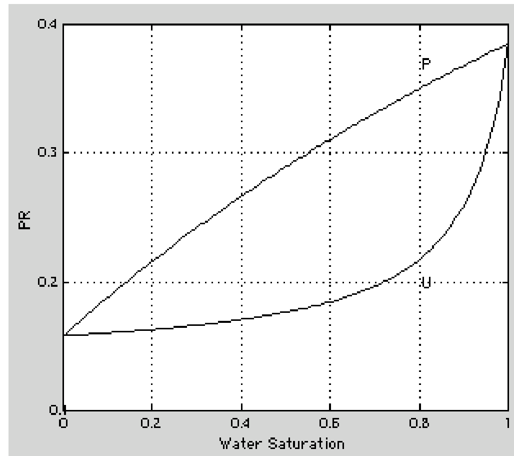

Figure 7. PR in sand versus water saturation. The lower curve is using the uniform saturation concept while the upper curve is for patchy saturation.

Situation 2: Fine Layering

Consider an interval containing three thin gas sand layers placed in water-saturated shale (Figure 8). The clay content in the shale is 70% while in the sand it is 5%. The total porosity in the shale is 30% while in the sand it is 25%. Finally, we assume that the water saturation in the sand is 30%.

We calculate the elastic constants in this interval according to the uncemented sand model and display the resulting impedance and PR in Figure 8. The impedance in the sand is slightly smaller than in the shale while, as expected, PR in the sand is significantly smaller than in the shale.

If the layers are thin and below the resolution of sonic and dipole tools, the elastic constants recorded will be the average of those of sand and shale. To fully ascertain the effect of subresolution layering on the reading of the tool one has to conduct full-wave-form simulation. A simple approximate way of quantifying this effect is through the Backus (1962) average (upscaling).

The resulting Backus-averaged impedance and PR in the interval are also shown in Figure 8. The PR in the gas sand sequence may become as large as 0.35 which is significantly different from the local (subresolution) PR value of about 0.17 in the sand. Although both the impedance and PR in the sand sequence remain smaller than in the surrounding shale, their upscaled values change dramatically. The observed change may explain abnormally high PR values sometimes observed in gas wells.

Notice that with respect to seismic prospecting this situation is different from that created by patchy saturation. If the layering is subresolution at the log scale it will certainly remain subresolution at the seismic scale. *Therefore, high PR measured at the well due to thin layering should not be corrected to ascertain the seismic response of virgin formation away from well control.*

Discussion and Conclusion

We offer two explanations to the abnormally high PR sometimes observed in well data in gas sand. The analysis has been conducted under the assumption of isotropy. Anisotropy may potentially contribute to the deviation of apparent PR from expected low values. Finally, we assumed that the interpretation of the data in terms of slowness is correct. No need to say that relentless effort has to be spent to assure the validity of this assumption.

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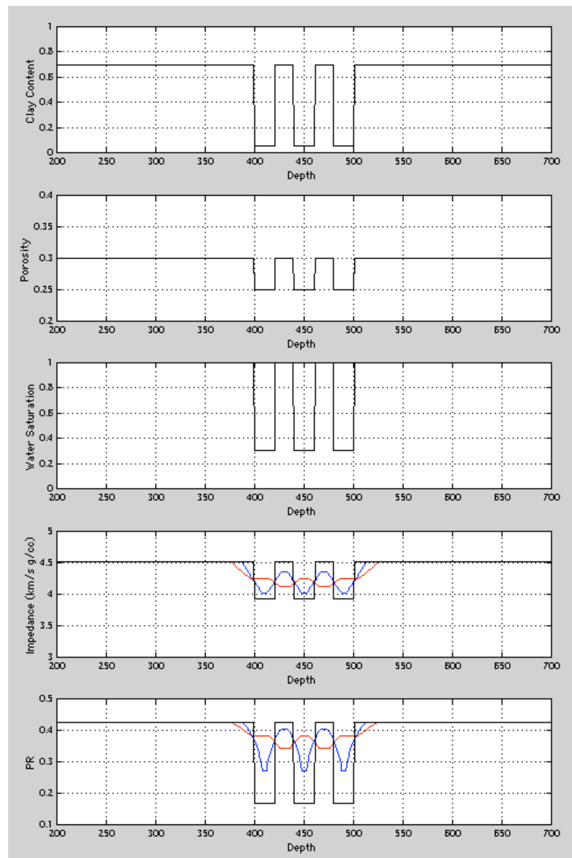

Figure 8. A hypothetical interval with three thin gas sand layers. The depth units are fictitious. In the impedance and PR frames, the black curves are for the fine-scale values while blue and red are for the Backus-upscaled results.