Fizz water and low gas-saturated reservoirs

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It is widely believed that gas dissolved in water or a few percent of a separate gas phase in water can make the pore fluid mixture very compressible. The fluid bulk modulus (K), the inverse of compressibility, would drop significantly and, in turn, P-wave velocity and impedance will decrease. This suggests that seismic techniques (e.g., DHI and AVO) cannot distinguish a water zone with small amounts of gas either dissolved or as a free phase in water from economic gas reservoirs.

In exploration, the tendency is to consider natural gases as extremely light fluids with negligible modulus. Figure 1 shows, under such an assumption, the effect of gas saturation on *P*-wave velocity of rocks (calculated using the Gassmann equation). With a low gas modulus of 0.01 Gpa (still more than 70 times higher than air modulus at room conditions), gas saturation of a few percent has an effect on *P*-wave velocity that is similar to that of full gas saturation. Data suggest that low gas saturation can generate similar seismic attributes but with false hydrocarbon indicators that are similar to those of economic gas reservoirs. Consequently, many dry holes drilled based on false hydrocarbon indicators have been attributed to this condition—widely known as the "fizz-water" effect.

Unfortunately, the fizz water concept has not been rigorously defined and examined although, as stated earlier, it is widely accepted among geophysicists. It has become a standard scapegoat for almost all failures of DHI or AVO applications including deepwater reservoirs. And, because the ill-defined fizz-water concept looks so logical, it may actually prevent efforts to find the real cause or develop new techniques for seismic evaluation of hydrocarbon saturation.

Deepwater reservoirs are often undercompacted and saturated with overpressured fluids, sometimes more than 69 MPa (10 000 Psi). This brings up an obvious question: Is the fizz water concept valid at such high pressures?

Figure 2 is an example of attributing an amplitude anomaly to fizz water. A strong reflection is observed at about 4.2 s two-way traveltime. Because this reflection is from a nonproductive zone, it has been suggested that the strong reflection is the result of areas of small gas saturation that would have been displaced by mud filtrate during drilling and thus not identified in the open-hole logs. Lower in the section, hydrocarbon zones are successfully identified, indicating the analysis is correct. But using realistic properties for the pore fluids at pressures and temperatures typical for this depth (6096 m) would exclude fizz from being the cause. Some other factors must be responsible.

In the remainder of this article, we analyze rock and fluid properties at deep reservoir conditions to carefully examine the fizz water concept. The goal is to eliminate some suspected scenarios and help reduce exploration risk.

Velocity and modulus of fizz water. One definition of fizz water is brine with dissolved gas. A relation for the effects of this dissolved gas on brine compressibility was published as long ago as 1945 and adopted later by Batzle and Wang and Castagna et al. (Figure 3).

The model suggests that the modulus of water with 5L/L gas in solution is significantly lower than that of gas-free water. As a consequence, rocks saturated with this fizz water

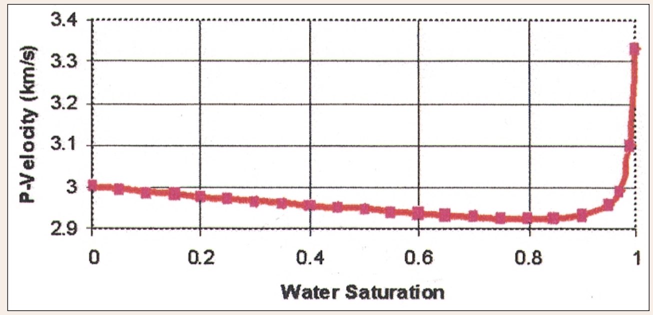

Figure 1. Typical effect of gas saturation on *P*-velocity of rocks under shallow conditions.

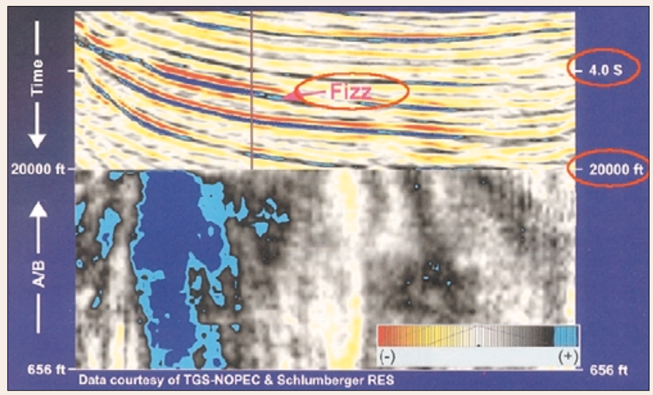

Figure 2. An example of fizz in deep reservoirs (from Hilterman).

were expected to have low compressional velocity and impedance. However, recently measured data demonstrate that dissolved gas has a negligible effect on water velocity. In Figure 4, both gas-free (dead) water and water with dissolved gas (live) of about 6.5 L/L methane (bubble point of 69 Mpa at 22°C) were measured as functions of pressure up to 103.5 MPa and temperatures up to 150°C. These data show that dissolved gas has negligible effect on water velocity. This result is consistent with static compressibility measurements (Osif, 1988). In fact, the amount of gas that can actually go in solution in water is overestimated in Figure 3 due to the restricted gas solubility (requires excessive bubble point pressures).

A possible alternative explanation is that, when pressure is lowered below the bubble point, gas bubbles come out of solution within the water to form a gas-water mixture. This free gas phase was expected to dramatically lower the overall fluid mixture modulus. However, measurements show that these exsolved gas bubbles at elevated pressures (69 Mpa bubble point in this case) have a negligible effect on total gas-water mixture volume and density (Figure 5).

This is due to small volume and high density of exsolved gas at elevated pressures. The gas effect on volume and density gradually increases but only becomes significant when pressure is significantly lower than 20 Mpa (3000 psi).

Clearly, at elevated pressures, gas properties are fundamentally different from those at the relatively low pressures normally assumed by explorationists.

Modulus of gas. It is often assumed that gas is so com-

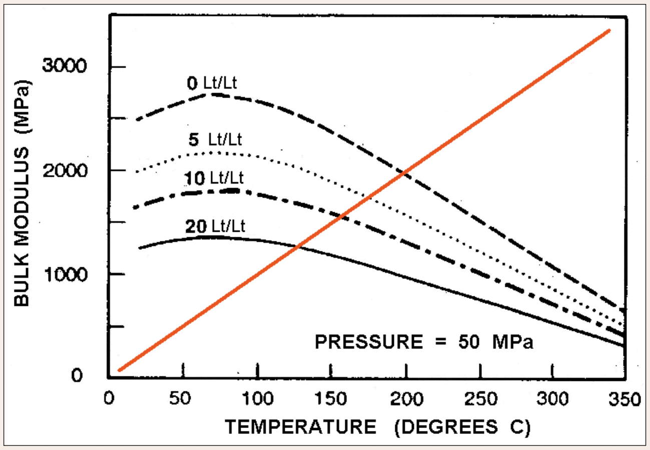

Figure 3. Calculation of the effect of gas in solution on water bulk modulus (from Castagna et al.).

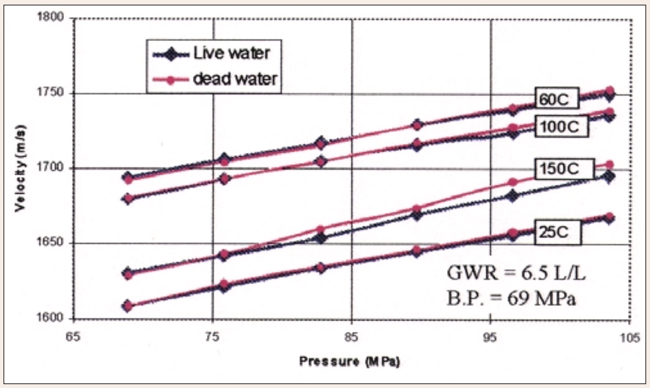

Figure 4. Measurements of "live" and "dead" water velocity at different pressure and temperature conditions.

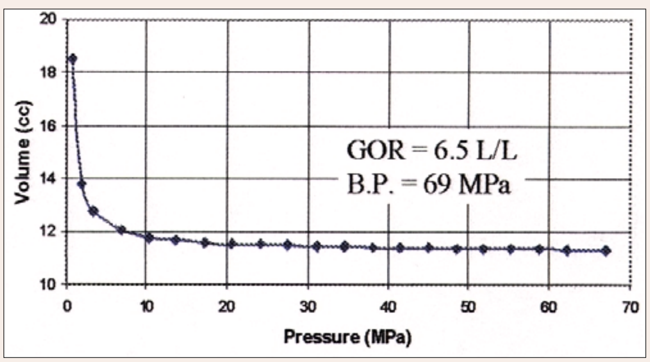

Figure 5. Volume-pressure relation for live water under bubble point.

pressible that it has an almost negligible modulus. However, the data in Figure 6 demonstrate that, with increasing pressure, gas can behave much like oil.

At the relatively low pressure of 15 MPa, velocity increases with increasing temperature—behavior similar to an ideal gas. When pressure increases to 20 MPa, the velocity of gas seems independent of temperature. At 41 MPa, the velocity of gas decreases with increasing temperature—similar to liquid oil behavior. At this point, in fact, these fluids are in the supercritical pressure-temperature region in which the distinction between gas and liquid is meaningless.

Figure 7 shows velocity data on a gas sample with gas gravity of 0.7 with pressures up to 103.4 Mpa and temperatures up to 150°C.

At elevated pressure, gas velocity can approach 1.2 km/s. The decrease in velocity with increasing temperature is significantly greater in the high pressure and low temperature

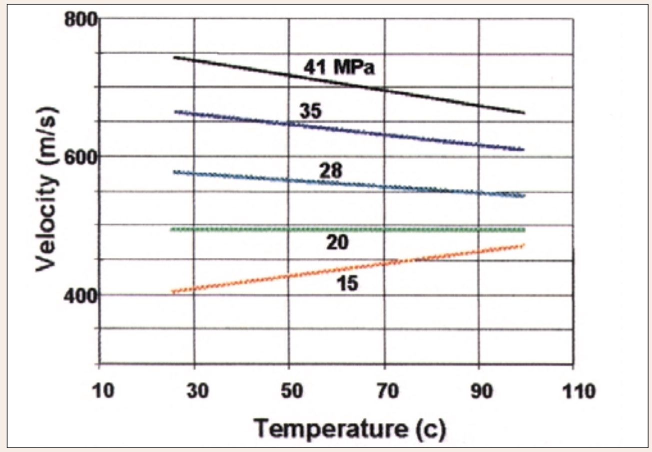

Figure 6. Measured velocities on gas show gas behavior at low pressure and liquid behavior at high pressure.

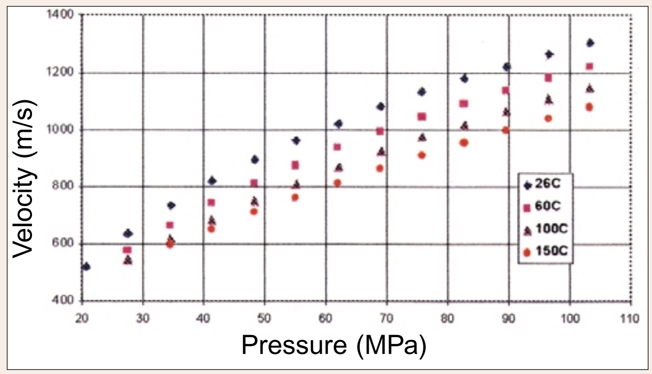

Figure 7. Measured velocity on a gas sample as a function of pressure and temperature. (Gas gravity is defined as the ratio of a gas molecular weight to that of air.)

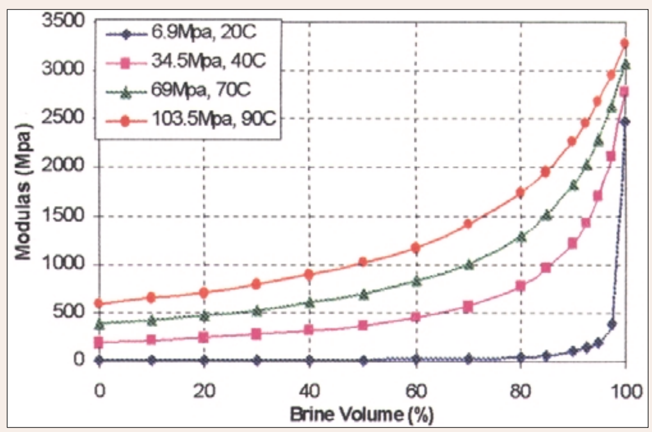

Figure 8. Modulus of gas-brine mixture at in-situ conditions.

range but negligible at pressures less than 30 Mpa and high temperatures. Clearly, real gas properties range from conventional light gas properties to almost liquid properties as pressure is increased. Note that under deepwater reservoir conditions, pore fluid pressure can be higher than 100 MPa.

Gas-water mixtures. Figure 8 shows the result when realistic gas properties are used to calculate the velocity and modulus of gas-water mixture based on the Wood equation.

Here we used gas with gravity of 0.78; brine with salinity of 50 000 ppm; pressures of 6.9, 34.5, 69, and 103.4 Mpa; and in-situ temperatures of 20, 40, 70, 90°C. The results show clearly that high-pressure gas (even at elevated temperature)

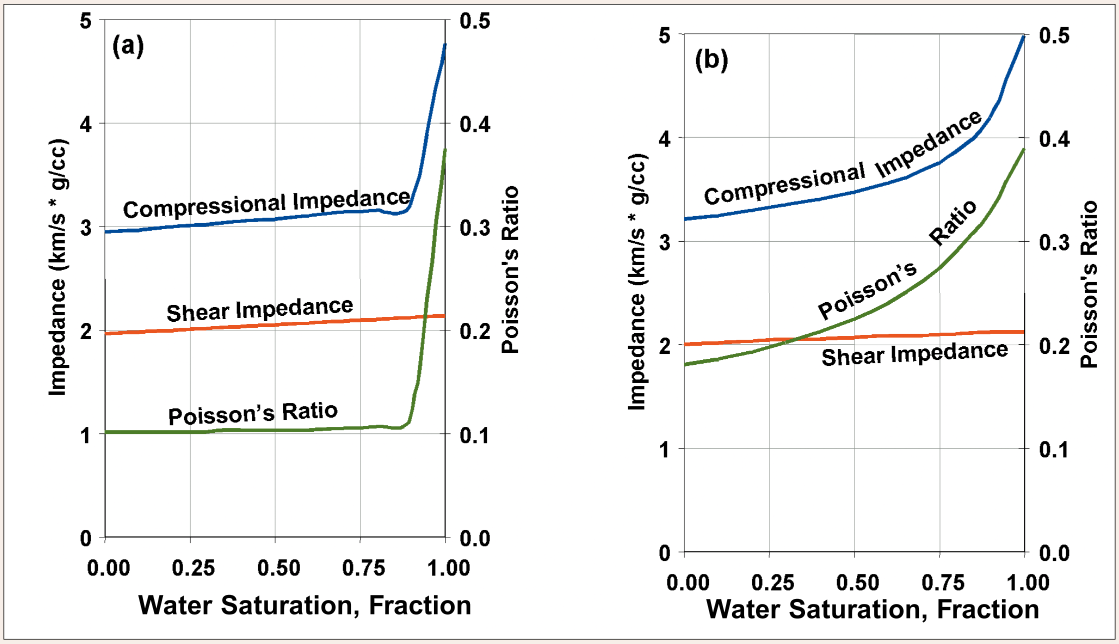

Figure 9. Calculated rock impedance and Poisson's ratio for (a) fizz water at low modulus gas (typical of shallow conditions) and (b) more realistic gas modulus for deep conditions. (a) Gas modulus (Kg)=0.00387 Gpa; water modulus (Kw)=2.435 Gpa. (b) Gas modulus (Kg)=0.248 Gpa; water modulus (Kw)=2.905 Gpa.

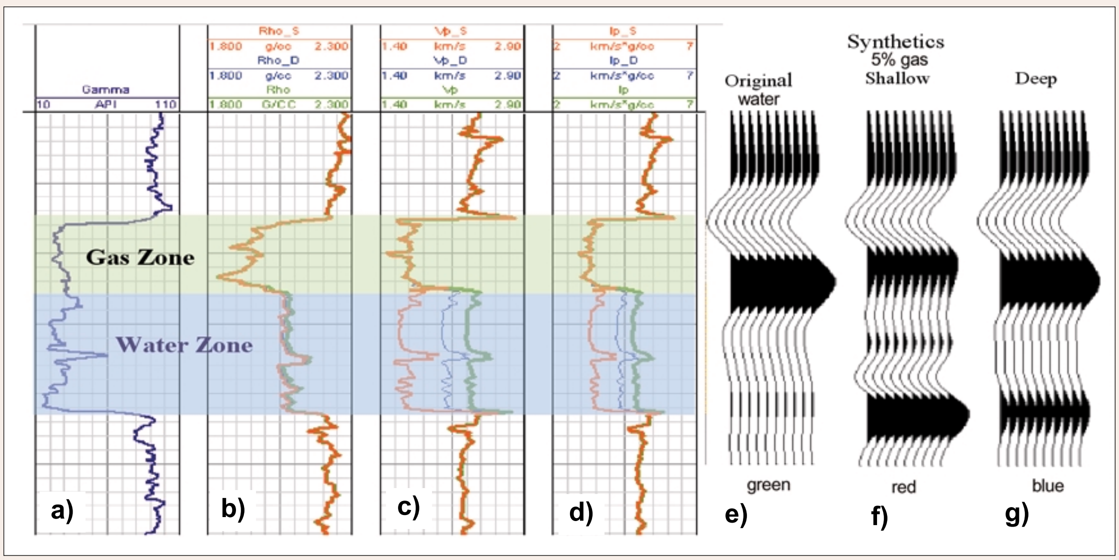

Figure 10. Gamma ray (a), density (b), velocity (c), impedance (d), and synthetic seismograms (e-g) calculated for the original water zone long (green curve) and for 5% gas-saturation effect on the water zone under shallow and deep conditions.

is much less effective at reducing the modulus of the gas-brine mixture. The Wood equation is an iso-stress static relation (Reuss bound), which provides a lower boundary for properties of fluid mixture. For seismic waves, in-situ conditions (fluid connectivity) may not satisfy iso-stress condition, and the gas-saturation effect on modulus of gas-fluid mixture may be closer to a linear than to an iso-strain condition (patchy saturation).

However, the impact that this realistic gas behavior has on rocks also can be calculated using the Gassmann equation. For a shallow reservoir (depth = 1000 ft) with a pore pressure of 3.4 MPa and temperature of 16°C, gas with gravity of 0.7 has modulus of 0.00387 GPa and density of 0.119 gm/cc. Brine with salinity of 50 000 ppm has bulk modulus of 2.435 Gpa. Based on these conditions, a few percent of free gas in a water-gas mixture can dominate the fluid mixture properties and thus the properties of a saturated rock. To demonstrate this, we assume a rock sample typical of a deepwater sand: porosity = 34%, dry *P*-wave velocity = 1.65 km/s, and *S*-wave velocity = 1.10 km/s. As seen in Figure 9a, compressional-wave impedance is not very sensitive to gas saturation ranging from Sg = 10 to 100% (water saturation, Sw < 90%), confirming a concept has been widely accepted as a cause for many false shows and dry holes.

At typical deepwater conditions (depth of 20 000 ft, pore pressure of 68.9 Mpa, and temperature of 121°C), gas with a gravity of 0.78 has a modulus of about 0.248 GPa and brine a modulus of 2.905 GPa. Heavy gas or gas condensate at high pressures (such as 69 MPa) may have a modulus more than 0.5 GPa. In that case, compressional-wave impedance shows a gradual change with gas saturation (Figure 9b). Thus, we may have a chance under these realistic conditions to quantitatively evaluate gas saturation from seismic.

Figure 10 shows these calculated shallow and deep fluid properties applied to a log from Gulf of Mexico. Figure 10a, a gamma-ray log, shows a massive sand zone (130 ft) with a gas cap (about 40 ft) above a water zone (about 90 ft). Figures 10b-d are the density log, *P*-wave velocity, and impedance log. Saturation conditions are color coded on the log curves: green = water, red = shallow fizz water, and blue = deep fizz water. The gas sand has a *P*-wave velocity of approximately 1.67 km/s and the water sand about 2.3 km/s (green line). A 1-D synthetic seismogram based on a 40-Hz Ricker wavelet shows a strong reflection at the shale-gas sand and gas-water interface, but this reflection is very weak at the bottom water-sand-shale interface (Figure 10e). If we assume that the water zone contains 5% gas (to simulate fizz water), we can simulate how the velocity and impedance of sand

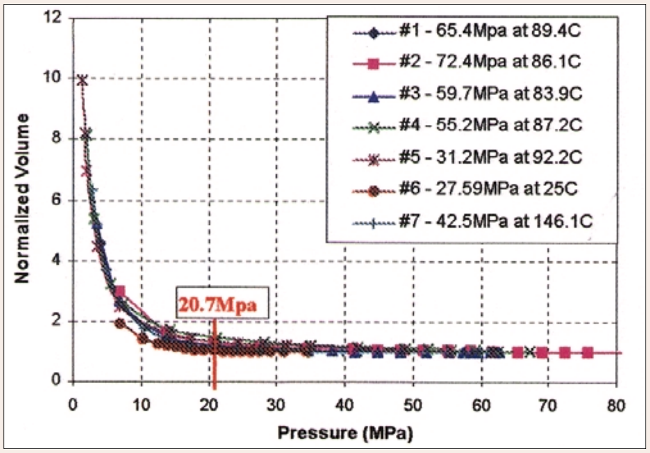

Figure 11. Pressure plotted against normalized total fluid mixture volume for exsolved gas-saturated oil system.

change under both shallow and deep conditions.

Under the shallow, low-pressure condition, 5% gas causes the fizz-water effect to reduce *P*-wave velocity and impedance. *P*-wave velocity of the fizz-water sand reduces to 1.60 km/s, lower than the gas-sand velocity (red curve in Figure 10c). Figure 10f shows no energy at the gas-water sand interface but strong energy at bottom of the sand-shale interface. Clearly, we cannot distinguish, via seismic, a fizz-water zone from an economic gas reservoir at this shallow depth. However, in deepwater, 5% gas has very different effect on the *P*-wave velocity (blue curve in Figure 10c). The fizz-gas reduces *P*-wave velocity from 2.3 km/s to 2.1 km/s and this velocity is still much higher than that for the shallow condition (1.60 km/s). The synthetics (Figures 10g) show reasonable energy reflected at the gas-water interface and some energy at the bottom sand-shale interface. Under these conditions, we have a chance to distinguish the low gas-saturated zone from an economic gas reservoir if we have high quality seismic data with true preserved amplitudes and use realistic fluid and rock properties to calibrate seismic attributes.

We can model the water zone to have a velocity around 1.6 km/s, just like the fizz-water effect in the shallow case. However, a gas saturation of 48% is needed to decrease the *P*-wave velocity to 1.60 km/s. This suggests that, if a similar amplitude effect is observed for the deep reservoir, it may contain a significant amount of gas and may be economic (if we consider a highly pressured gas with high density). Otherwise, we cannot blame fizz water for such a false hydrocarbon indicators at greater depths.

Gas-oil mixtures. Although much more gas can exsolve from oil than from water as pressure decreases well below bubble point pressure, the exsolved gas at high pressures has little effect on properties of a gas-oil mixture. In Figure 11, volumes versus pressures were measured for seven live oil samples. The measurements start from single phase at the bubble pressure, then pressure is gradually reduced. With decreasing pressure, gas exsolves from oil and the total sample volume (gas + oil) increases. For comparison, we plot the normalized volume (by the sample volume at the bubble point) as a function of pressure. The bubble point pressure ranges from 27.5 to 70 Mpa (4000 Psi to over 10 000 Psi).

At 20.7 MPa, much lower than the bubble pressure, a significant amount of gas is in the gas-oil mixture, but we only observe a minor total volume increase. These data suggest that it is difficult to detect exsolved gas at pressures higher than about 20.7 MPa.

Thus, dissolved gas in water or gas coming out of solution from either water or oil at pressures higher than 20 Mpa is not likely be detected seismically. Seismic anomalies at such high pressures may not relate to the standard concepts of fizz water or fizz oil.

Patchy saturation effects. Gassmann's equation assumes that pore fluids are in pressure equilibrium in all pores. For the gas-water mixture, homogeneous gas distribution on a pore scale is the easiest case for pressure equilibrium. This can occur when fluid pressure drops lower than the bubble point or gas leaks through the sediment column (gas chimney). Homogeneously distributed low-pressure gas causes a low fluid modulus for the overall mixture and low rock compressional velocity at seismic frequencies. However, this may not be the case for the original gas distribution in situ. This distribution could be very complicated and related to pore connectivity, capillarity forces, buoyancy, and many large-scale factors such as the gas source, stratigraphy, structure, lithology, seal, and leakage. Thus gas distribution could be very complex. Trapped original gas may be distributed in a patchy way, such as in layers or gas pockets with no communication with the surrounding media. An important unanswered question is how to identify gas distributions and their effects on seismic attributes.

Conclusions. Fizz water is an ill-defined and misapplied concept. Contrary to widespread belief, dissolved gas or gas exsolving out of water or oil at high pressure (>20 MPa) has little effect on properties of pore fluid mixture. Realistic gas, fluid, and rock properties must be used to evaluate fluid mixture effects on rocks. Low gas saturation may have large effects on seismic impedance only in shallow formations with low pressures.

High-pressure gas has very different effects on rock velocity and offers a better chance to evaluate gas saturation. However, seismic evaluation of gas saturation in deepwater remains difficult.

Suggested reading. "Seismic properties of pore fluids" by Batzle and Wang (GEOPHYSICS, 1992). "Effect of brine-gas mixture on velocity in an unconsolidated sand reservoir" by Domenico (GEOPHYSICS, 1976). *Seismic Amplitude Interpretation* by Hilterman (SEG 2001 Distinguished Instructor Short Course). "Velocity, density, and modulus of hydrocarbon fluids—Data measurement" by Han and Batzle (SEG 2000 *Expanded Abstracts*). "Velocity, density and modulus of hydrocarbon fluids—Empirical modeling" by Han and Batzle (SEG 2000 *Expanded Abstracts*). "Acoustic measures of partial gas saturation in tight sandstones" by Murphy (*Journal of Geophysical Research*, 1984). "The effect of salt, gas, temperature, and pressure on the compressibility of water" by Osif (*Reservoir Engineering*, 1988). *A Textbook of Sound* by Wood (MacMillan, 1955). E

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