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In honor of the new millennium (Y2K), the SEG Research Committee is inviting a series of review articles and tutorials that summarize the state-of-the-art in various areas of exploration geophysics. The present article by Dr. Zhijing (Zee) Wang is the first of this series, and deals with the rapidly evolving field of rock physics. Further invited contributions will appear during the next year or two—Sven Treitel, Chairman, SEG Research Subcommittee on Y2K Tutorials and Review Articles.

Y2K Tutorial

Fundamentals of seismic rock physics

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INTRODUCTION

During the past 50 years or so, tremendous progress has been made in studying physical properties of rocks and minerals in relation to seismic exploration and earthquake seismology. During this period, many theories have been developed and many experiments have been carried out. Some of these theories and experimental results have played important roles in advancing earth sciences and exploration technologies. This tutorial paper attempts to summarize some of these results.

In exploration seismology, seismic waves bring out subsurface rock and fluid information in the form of travel time, reflection amplitude, and phase variations. During the early years of exploration seismology, seismic data were interpreted primarily for structures that might trap hydrocarbons. With the advancement of computing power and seismic processing and interpretation techniques, seismic data are now commonly analyzed for determining lithology, porosity, pore fluids, and saturation. Because rock physics bridges seismic data and reservoir properties and parameters, it has been instrumental in recent years in the development of technologies such as 4-D seismic reservoir monitoring, seismic lithology discrimination, and direct hydrocarbon detection with "bright-spot" and angle-dependent reflectivity analyses.

Seismic properties are affected in complex ways by many factors, such as pressure, temperature, saturation, fluid type, porosity, pore type, etc. These factors are often interrelated or coupled in a way that many also change when one factor changes. The effect of these changes on seismic data can be either additive or subtractive. As a result, investigation of the effect of varying a single parameter while fixing others becomes imperative in understanding rock physics applications to seismic interpretations. Table 1 shows some factors influencing seismic properties of rocks. These factors will be summarized and elaborated in a later section.

Because of the vast amount of information in the literature on rock physics, it is impossible to summarize every theory and every experimental finding in this paper. The objective of this tutorial paper, as opposed to a review paper, is not to present a comprehensive review on rock physics; instead, I attempt to discuss some of the most important, yet practical, theories and major factors that influence *seismic* properties of sedimentary rocks. As such, most of the discussions are qualitative and descriptive.

This paper only covers a fraction of existing knowledge in rock physics and is not intended for rock physics experts, The targeted readers are students and potential users as an introduction to seismic rock physics. For those who are interested in in-depth knowledge of rock physics, see Bourbie et al. (1987), Nur and Wang (1989), Wang and Nur (1992, 2000), and Mavko et al. (1998). For those who are interested in other physical properties of rocks, see Gueguen and Palciauskas (1994) and Schön (1995).

This tutorial consists of three parts: fluid substitution, factors influencing seismic properties, and rock physics challenges. In the first part, I present the most commonly used tool for fluid substitution (the Gassmann equation) and discuss its applicability and assumptions. It is naturally followed by discussions on tools for obtaining pore fluid properties because one of the most important input parameters to the Gassmann equation is fluid properties. The second part discusses effects of various rock and reservoir parameters on seismic properties and tabulates some rules of thumb of rock physics. Finally, I briefly discuss several issues and challenges in applying rock physics.

FLUID SUBSTITUTION: THE GASSMANN EQUATION

The Gassmann (1951) equation has been used for calculating the effect of fluid substitution on seismic properties using the frame properties. It calculates the bulk modulus of a fluid-saturated porous medium using the known bulk moduli of the solid matrix, the frame, and the pore fluid. For a rock, the solid matrix consists of the rock-forming minerals, the frame refers to the skeleton rock sample, and the pore fluid can be a gas,

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oil, water, or a mixture of all three:

$$K^* = K_d + \frac{(1 - K_d/K_m)^2}{\dfrac{\phi}{K_f} + \dfrac{1-\phi}{K_m} - \dfrac{K_d}{K_m^2}}, \quad (1)$$

where K^* is the bulk modulus of a rock saturated with a fluid of bulk modulus K_f, K_d is the frame bulk modulus, K_m is the matrix (grain) bulk modulus, and ϕ is porosity. The shear modulus G^* of the rock is not affected by fluid saturation, so that

$$G^* = G_d, \quad (2)$$

where G_d is the frame shear modulus of the rock. The density ρ^* of the saturated rock is simply given by

$$\rho^* = \rho_d + \phi\rho_f. \quad (3)$$

where ρ^* and ρ_d are the fluid-saturated and dry densities of the rock, respectively, and ρ_f is the pore fluid's density. Note that $\rho_d = (1-\phi)\rho_m$, where ρ_m is the matrix (grain) density.

The frame bulk and shear moduli are calculated using the measured velocities in the frame rock:

$$K_d = \rho_d\left(V_p^2 - \frac{4}{3}V_s^2\right), \quad (4)$$

$$G_d = \rho_d V_s^2. \quad (5)$$

It is important to point out that the frame moduli are not the same as the dry moduli. In the correct use of the Gassmann equation, frame moduli should be measured at irreducible saturation conditions of the wetting fluid (normally water). The irreducible fluid is part of the rock's frame, not the pore space. Overdrying a rock in the laboratory will result in erroneous Gassmann results.

The bulk modulus K_f of a fluid mixture can be calculated using Wood's equation (Wood, 1941):

$$\frac{1}{K_f} = \frac{S_w}{K_w} + \frac{S_o}{K_o} + \frac{S_g}{K_g}, \quad (6)$$

where K_w, K_o, and K_g are the bulk moduli of water, oil, and gas, respectively; S_w, S_o, and S_g are the water, oil, and gas saturations, respectively, expressed as volume fractions of the pore space; and $S_w + S_o + S_g = 1$. Equation (6) implies that the pore fluid is uniformly distributed in the pores.

Table 1. Factors influencing seismic properties of sedimentary rocks (with increasing importance from top to bottom).

Rock properties	Fluid properties	Environment
Compaction	Viscosity	Frequency
Consolidation history	Density	Stress history
Age	Wettability	Depositional environment
Cementation	Fluid composition	Temperature
Texture	Phase	Reservoir process
Bulk density	Fluid type	Production history
Clay content	Gas-oil, gas-water ratio	Layer geometry
Anisotropy	Saturation	Net reservoir pressure
Fractures		
Porosity		
Lithology		
Pore shape		

The bulk density ρ_f of the fluid mixture is calculated by

$$\rho_f = S_w\rho_w + S_o\rho_o + S_g\rho_g, \quad (7)$$

where ρ_w, ρ_o, and ρ_g are the bulk densities of water, oil, and gas, respectively.

The basic assumptions for the Gassmann equation are that

1) The rock (both the matrix and the frame) is macroscopically homogeneous.
2) All the pores are interconnected or communicating.
3) The pores are filled with a frictionless fluid (liquid, gas, or mixture).
4) The rock-fluid system under study is closed (undrained).
5) The pore fluid does not interact with the solid in a way that would soften or harden the frame.

Assumption (1) is common to many theories of wave propagation in porous media. It assures that the wavelength is long compared to the grain and pore sizes. For most rocks, waves with frequencies ranging from seismic to laboratory frequencies can generally meet this assumption. Brown and Korringa (1975) extended Gassmann's equation to anisotropic rocks.

Assumption (2) implies that the porosity and permeability are high and there are no isolated or poorly connected pores in the rock. The purpose of this assumption is to ensure full equilibrium of the pore fluid flow, induced by the passing wave, within the time frame of half a wave period. The pore interconnectivity is therefore relative to the wavelength or frequency. For the Gassmann equation, which assumes an infinite wavelength (zero wave frequency), most rocks can meet this assumption no matter how poorly the pores are interconnected. For seismic waves, however, only unconsolidated sands can approximately meet this assumption because of the sands' high porosity and permeability (Wang, 2000a). For high-frequency waves such as those used in logging and in the laboratory, most rocks may not meet this assumption. Consequently, the log- or lab-measured velocities are often higher than those calculated with the Gassmann equation.

Assumption (3) implies that the viscosity of the saturating fluid is zero. The purpose of this assumption is again to ensure full equilibrium of the pore fluid flow. This assumption is also relative to the wavelength or frequency. If the wave frequency is zero, fluids with any viscosity will equilibrate within the time frame of half a wavelength (infinite time). If the viscosity is zero, the pore fluid will be easy to equilibrate. In reality, because all fluids have finite viscosities and all waves have finite wavelengths, most calculations using the Gassmann equation will violate this assumption.

Assumptions (2) and (3) are the key points, and constitute the essence of the Gassmann equation. They imply that the wave frequency is zero. This is perhaps the reason why the measured laboratory and logging bulk modulus or velocity are usually higher than those calculated with the Gassmann equation. At finite frequencies, relative motion between the solid matrix and the pore fluid will occur, so that the waves are dispersive. The relative motion between the pore fluid and the rock matrix is caused by the finite wavelength and the high contrast in bulk and shear moduli between the pore fluid and the rock matrix.

Assumption (4) means that for a laboratory rock sample, the rock-fluid system is sealed at the boundaries so that no fluid can flow in or out of the rock's surface. For a rock volume v, which is part of a much larger volume V_o (such as a formation in a reservoir), the system v must be located within V_o at such a distance from the surface of V_o that the stress variations generated by the passing wave do not cause any appreciable flow through the surface of v. This is the key in calculating the effect of pore fluid change on seismic properties with the Gassmann equation, because if the system is open, changes in seismic properties due to pore fluid changes will only be related to the fluid density change.

Assumption (5) eliminates any effects of chemical/physical interactions between the rock matrix and the pore fluid. In reality, the pore fluid will inevitably interact with the rock's solid matrix to change the surface energy. When a rock is saturated by a fluid, the fluid may either soften or harden the matrix. For example, when loose sand grains are mixed with a heavy oil, the mixture will have higher bulk and shear moduli. When a shaley sandstone is saturated with fresh water, the rock's matrix is often softened due to clay swelling. An extreme case is that a dried mud (clay-water mixture) has higher elastic moduli than the water-saturated clay. This is partly why one should never overdry shaley rocks in the lab. This also emphasizes that the input "dry" frame bulk modulus to the Gassmann equation should be obtained at irreducible fluid saturation conditions.

As seen in equations (1)–(7), the Gassmann equation requires several input parameters to calculate fluid effects on seismic velocities. The dry frame bulk and shear moduli, porosity, grain density, and the fluid bulk modulus (incompressibility) are mostly measured in the lab. If lab data are not available, they can often be measured or estimated through well logs or empirical relations. For example, porosity can be derived from neutron or acoustic logs. Dry frame moduli can be either estimated using the backward Gassmann equation if other input parameters are known or derivable from acoustic log data. Such information can come from gas- and oil/water-saturated sections in the same well, assuming that lithology does not vary. However, the log-derived parameters are usually inaccurate as they are indirect measurements and affected by hole conditions, saturation, and lithology variations.

From equation (1), the backward Gassmann equation can be derived as

$$K_d = \frac{K^*\left(\dfrac{\phi K_m}{K_f} + 1 - \phi\right) - K_m}{\dfrac{\phi K_m}{K_f} + \dfrac{K^*}{K_m} - 1 - \phi}. \tag{8}$$

The input grain (matrix) bulk and shear moduli are from the moduli of the minerals that comprise the rock. If mineralogy is known for the rock, one can use the Voight-Reuss-Hill (VRH) average (Hill, 1952) to calculate an effective K_m and G_m:

$$M = \frac{1}{2}(M_V + M_R) \tag{9}$$

where M is the effective grain modulus (which can be either K_m or G_m), M_V is the Voigt (1928) average,

$$M_V = \sum_{i=1}^{n} c_i M_i, \tag{10}$$

and M_R is the Reuss (1929) average,

$$\frac{1}{M_R} = \sum_{i=1}^{n} \frac{c_i}{M_i}, \tag{11}$$

where c_i and M_i are the volume fraction and the modulus of the ith component, respectively. The effective medium is macroscopically isotropic. Hashin and Shtrikman (1963) provide a more tightly bounded but more complicated estimate of M. For practical purposes, when the elastic constants of the components do not differ widely, the VRH and Hashin-Shtrikman models yield similar results.

Wang (2000a) carried out an extensive comparison between Gassmann predicted results and laboratory data. He shows that for rocks with interconnected high aspect-ratio ($\approx$1) pores such as unconsolidated clean sands and sandstones at high effective pressures, little difference exists between Gassmann-calculated and laboratory-measured seismic velocities (The aspect ratio of a two-dimensional pore is defined as the short axis divided by the long axis. It is always less or equal to one). For rocks with very low aspect-ratio ($\ll$1) pores such as poor grain contacts, cracks, or fractures, velocities measured at seismic frequencies may be closer to the laboratory-measured values than to the Gassmann-calculated values. For these rocks, significant wave dispersion may occur at very low frequencies, especially when these rocks are saturated with high-viscosity pore fluids, so that both the seismic and laboratory frequencies are in the same "high" frequency band.

For rocks with medium to low aspect-ratio pores, velocities measured at seismic frequencies are higher than the Gassmann-calculated values but lower than the laboratory-measured values. However, the real magnitudes of the deviation of the seismic data from either the Gassmann equation predictions or from the laboratory-measured data will remain unknown until the Gassmann equation can be rigorously verified in the laboratory or in the field.

Wang (2000a) also compared the Gassmann results and laboratory results of the effect of fluid displacement on seismic properties. The effects of fluid displacements on seismic velocities agree well between the Gassmann-predicted and laboratory-measured values, provided that the frame properties provided to the Gassmann equation (K_d, G_d, and ρ_d) are measured at the irreducible water saturation or under moist conditions. Figure 1 shows the effect of fluid displacement (water and CO_2 flood) on compressional velocities (V_p) in sands, sandstones, and dolomites. The Gassmann-calculated V_p change as a result of fluid displacement is very close to what is measured in the laboratory (Figure 1a). For shear velocities (Figure 1b), the Gassmann equation predicts slightly greater effects of fluid displacement compared to those measured in the laboratory.

The results shown in Figure 1 suggest that the fluid displacement process, though not necessarily the rock, approximately conforms with the Gassmann assumptions as only the fluids in large, well connected pores are likely to be swept. As a result, when the input frame properties are measured at the irreducible water saturation condition, the Gassmann-predicted and the laboratory-measured effects of fluid displacements on seismic properties might be directly applied to 4-D seismic feasibility studies and interpretations.

Biot (1956a, b, 1962) extended the Gassmann equation to the full frequency range. At zero frequency, Biot's theory reduces to the Gassmann equation. At an infinite frequency, Biot's theory can be described by a set of analytical equations (Geertsma and Smit, 1961). However, Biot's theory predicts very little velocity dependence on frequency because the calculated velocity difference between zero and infinite frequencies is usually less than 3% for most reservoir rocks (Winkler, 1985; Wang and Nur, 1990a). As a result, the Gassmann equation, rather than Biot's full-frequency theory, is often used in fluid substitution analysis.

Many other models exist in addition to Gassmann's and Biot's theories. For a comprehensive review, see Wang and Nur (1992) and Mavko et al. (1998).

PORE FLUID PROPERTIES

One of the ultimate goals of exploration seismology is to delineate and map pore fluids and their type and distribution in petroleum reservoirs. To achieve this goal, seismic data has to be able to resolve the compressibility contrasts among different pore fluids in the reservoir. As a result, seismic properties of pore fluids have to be fully understood.

Batzle and Wang (1992) summarized seismic properties of commonly encountered pore fluids based on their own data as well as on the literature. Their correlations are now being widely used in the oil industry.

Hydrocarbon gases

Batzle and Wang (1992) present a set of equations for calculating the bulk modulus and density of hydrocarbon gases. Because most gases are extremely compressible under reservoir conditions, in many cases the bulk modulus (incompressibility) of a hydrocarbon gas can be set as 0.01 to 0.2 GPa in seismic modeling. Errors in gas bulk modulus will yield little uncertainty in the calculated seismic properties in a fluid-saturated rock. An excellent source for thermophysical properties of methane, ethane, and butane can be found in Younglove and Ely (1987) where both acoustic velocity and bulk density are given along with other physical parameters.

Carbon dioxide (CO_2)

CO_2 is often injected into hydrocarbon reservoirs to displace oil. The displacement process can be either miscible or immiscible depending on pressure and temperature. Furthermore, many gas reservoirs produce substantial amount of CO_2 that has to be disposed of. One disposal process is injecting it into geological formations. Seismic technologies can be used to monitor the injected CO_2 and its displacement process (Langan et al., 1997) only if the injected CO_2 causes sufficient changes in seismic properties of the formation rock. CO_2 properties are therefore needed for modeling and interpreting seismic data. Vargaftik (1975) presents some data on CO_2 properties as functions of pressure and temperature.

Hydrocarbon oils

Both the bulk modulus and density of hydrocarbon oils increase with pressure, but decrease with increasing temperature. Batzle and Wang (1992) presented a set of empirical equations for calculating hydrocarbon oil properties as functions of pressure and temperature:

$$\rho = \frac{\rho_o + (0.00277P - 1.71 \times 10^{-7}P^3)(\rho_o - 1.15)^2 + 3.49 \times 10^{-4}P}{0.972 + 3.81 \times 10^{-4}(T + 17.78)^{1.175}}, \tag{12}$$

$$V = 2096\left(\frac{\rho_o}{2.6 - \rho_o}\right)^{1/2} - 3.7T + 4.64P + 0.0115\left[\left(\frac{18.33}{\rho_o} - 16.97\right)^{1/2} - 1\right]TP, \tag{13}$$

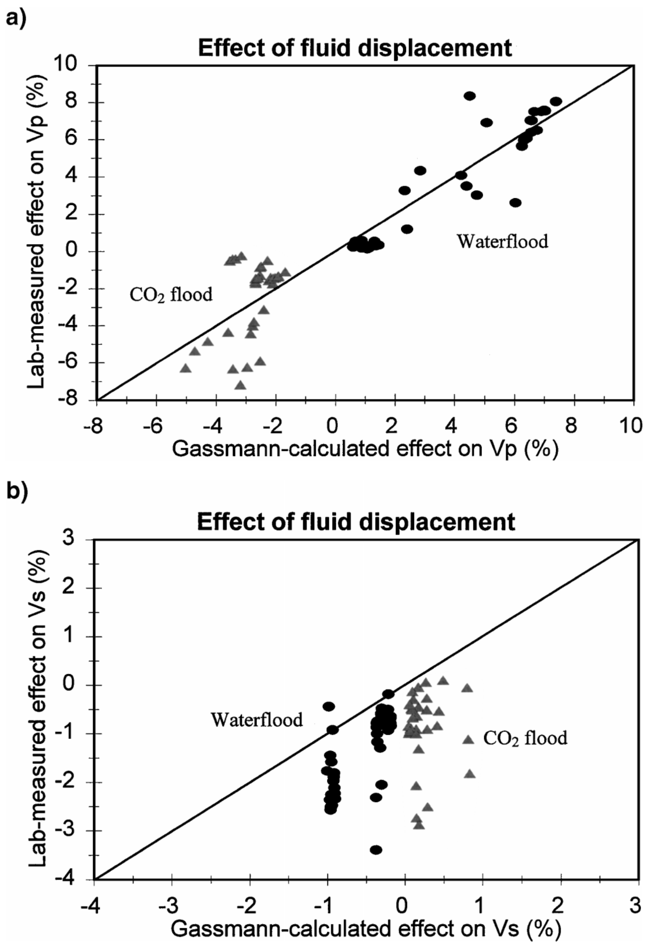

FIG. 1. Gassmann-calculated versus lab-measured effects of fluid displacement (water and CO_2 flood) on compressional (a) and shear (b) velocities in sands, sandstones, and dolomites. Solid circles are waterflooded sandstones and sands, triangles are CO_2-flooded dolomites.

$$K = \rho V^2, \quad (14)$$

where ρ, V, and K are the bulk density (g/cm^3), velocity (m/s), and bulk modulus (kPa), respectively, at pressure P(MPa) and temperature T(°C); ρ_o is a reference density measured at 15.6°C and one atmosphere.

Equations (12) and (13) are valid for dead oils (oils without dissolved gases) only. For live oils (oils with dissolved gases), one needs to substitute the saturation density ρ_G for ρ_o in equation (12) and the pseudo density ρ' for ρ_o in equation (13):

$$\rho_G = \frac{\rho_o + 0.0012 R_G G}{B_o}, \quad (15)$$

$$\rho' = \frac{\rho_o}{(1 + 0.001 R_G) B_o}, \quad (16)$$

where

$$B_o = 0.972 + 0.00038 \left[2.495 R_G \left(\frac{G}{\rho_o} \right)^{1/2} + T + 17.8 \right]^{1.175} \quad (17)$$

is called the formation volume factor and G is gas specific gravity (relative to air). R_G is gas-to-oil ratio (GOR) in liter/liter (1 liter/liter = 5.615 ft^3/bbl).

Water and brine

Water is a fluid that possesses several abnormal properties due in part to the electronic polarity of the water molecule: (1) Under atmospheric pressure, water's density reaches a maximum at 4°C, (2) for its molecular weight, water has abnormally high boiling point and melting points, and (3) unlike hydrocarbon liquids in which acoustic velocities decrease monotonically with increasing temperature, acoustic velocity in water increases with increasing temperature, reaches a maximum at around 73°C, and then decreases as temperature further increases at atmospheric pressure. Acoustic velocities and bulk densities in gas-free water and brine can be calculated using the equations summarized in Batzle and Wang (1992):

$$\begin{aligned}\rho_w = {} & 1.0 + 10^{-6}(-80T - 3.3T^2 + 0.00175T^3 + 489P \\ & - 2TP + 0.016T^2 P \\ & - 1.3 \times 10^{-5} T^3 P - 0.333P^2 - 0.002TP^2), \quad (18)\end{aligned}$$

$$\begin{aligned}\rho_b = {} & \rho_w + 0.668S + 0.44S^2 + 10^{-6} S[300P - 2400PS \\ & + T(80 + 3T - 3300S - 13P + 47PS)], \quad (19)\end{aligned}$$

$$V_w = \sum_{i=0}^{4} \sum_{j=0}^{3} w_{ij} T^i P^j,$$

$$\begin{aligned}V_b = {} & V_w + S(1170 - 9.6T + 0.055T^2 - 8.5 \times 10^{-5} T^3 \\ & + 2.6P - 0.0029TP - 0.0476P^2) + S^{1.5}(780 - 10P \\ & + 0.16P^2) - 1820S^2, \quad (20)\end{aligned}$$

where ρ_w and ρ_b are the bulk density of water and brine, respectively; V_w and V_b are the velocities of water and brine, respectively; S is salinity in weight fraction, T is temperature in °C, and P is pressure in MPa. The constants w_{ij} can be found in Batzle and Wang (1992).

Once the velocity and bulk density have been calculated, the bulk modulus can be obtained from equation (13).

Gas-in-water solutions and mixtures

Dodson and Standing (1945) found that for small amounts of dissolved gases, the compressibility of water increases almost linearly with the gas-to-water ratio in water containing dissolved gases:

$$\beta_G = \beta_B (1 + 0.0494 R_G), \quad (21)$$

where β_G is the compressibility of water with dissolved gases, β_B is the compressibility of gas-free water, and R_G is the gas-to-water ratio in liter/liter. Sergeev (1948) also reported substantial compressibility increases as gases are dissolved in brine.

For many years, equation (21) has been used for estimating water and brine compressibilities as functions of dissolved gases. However, this equation predicts too much dependence of water compressibility on the amount of dissolved gases. For example, a gas-to-water ratio of 10 liter/liter (56.2 ft^3/bbl) would increase the compressibility by 50%!

Osif (1988) studied the effects of salt, gas, temperature, and pressure on the compressibility of water. Contrary to Dodson and Standing (1945), Osif's results show little to no effect of gas in solution on compressibilities of water and brine.

Osif's findings were confirmed by Liu (1998), who studied the effect of dissolved methane, nitrogen gas, CO_2, and ammonia on acoustic velocities in water. His results show that the dissolution of methane and nitrogen gas in water has little effect on the acoustic velocities. The dissolution of CO_2 and NH_3 increases the acoustic velocities in water substantially. In CO_2-water solution, acoustic velocity increases by about 50 m/s (about 3%) as CO_2 is dissolved into water at room temperature and about 400 psi. In NH_3-water solution, acoustic velocity increases by about 150 m/s (about 10%) as NH_3 is dissolved into water at room temperature and about 75 psi. Such magnitude increases are so substantial that they cannot be neglected in practice.

Steam

Acoustic properties of steam and hot water are important for seismic modeling and interpretation of 4-D seismic monitoring data. The American Society of Mechanical Engineers (ASME) published tables of specific volumes of water and steam versus pressure and temperature (Meyer et al., 1979). The specific volume data can be converted to isothermal bulk modulus data through

$$K_T = -v \frac{\partial P}{\partial v}, \quad (22)$$

where v is specific volume, P is pressure in MPa, and K_T is the isothermal bulk modulus in MPa.

Because acoustic velocities are governed by the adiabatic bulk modulus and bulk density, the isothermal bulk modulus K_T has to be converted to the adiabatic bulk modulus K through

$$K = \frac{C_P}{C_v} K_T, \quad (23)$$

where C_p and C_v are the specific heats at constant pressure and volume, respectively. In the laboratory, C_p and C_v cannot be obtained easily and accurately, so we assume a constant C_p over C_v ratio of 1.5 in our calculations.

Figure 2a shows the adiabatic bulk modulus of water and steam versus temperature and pressure. The bulk modulus drops sharply as water transforms to steam. Figure 2b shows the bulk density of water and steam versus temperature and pressure. Bulk density also drops sharply as water transforms to steam. The bulk modulus in water increases with temperature up to about 73°C. It then decreases as temperature further increases.

For properties of fluids not discussed here (e.g., drilling muds), see Wang and Nur (2000).

FLUIDS AND SATURATION

One of the key factors in 4-D seismic reservoir monitoring and angle-dependent reflectivity [amplitude variation with offset (AVO)] is the seismic response to fluid saturation and substitution. Rocks saturated with less compressible fluids show higher P-wave velocities and impedances. S-wave velocities and impedances are much less affected by pore fluids because fluids have no rigidity. Consequently, rocks with less compressible fluids have higher velocity ratios (V_p/V_s). Such V_p and V_p/V_s dependence on pore fluid type is the physical basis for use of angle-dependent reflectivity for direct hydrocarbon detection and fluid delineation. The velocity and impedance dependence on pore fluid type and saturation makes 4-D seismology a powerful tool for reservoir fluid mapping and monitoring.

Although good pore fluid compressibility contrasts are necessary for 4-D and AVO, they may not be sufficient because seismic reflectivity is dependent on both fluid properties and rock properties. Fluid effects on rocks with stiff pores (hard rocks) are always smaller than those on rocks with compliant pores (soft rocks). Figure 3 shows the P-wave impedance change as a result of water flood in 44 sandstone and sand samples versus porosity. Low porosity rocks, which tend to have hard elastic frames, show smaller waterflood effect on seismic impedances. However, fluid saturation effects are controlled by the compressibility of the pores (or pore shape), not necessarily all by porosity. Rocks with cracks or fractures, no matter how low the porosity may be, always show a large effect of fluid saturation on seismic velocity. This is because cracks and fractures are very compliant.

POROSITY, PORE SHAPE, AND CLAY CONTENT

Velocity and impedance of rocks decrease with increasing porosity. Such velocity- or impedance-porosity relationships, however, are only statistically valid because seismic properties of a rock are more affected by the pore shape than by porosity (e.g., Kuster and Toksoz, 1974). For example, a low-porosity rock with flat, low-aspect ratio pores may have lower seismic velocities than a high-porosity rock with spherical, high-aspect ratio pores because flat pores are much more compressible than spherical pores. As a result, the scatter in a velocity- or impedance-porosity relationship can be partly attributed to differences in pore shapes among rock samples. However, pore shape varies in wide ranges in sedimentary rocks and is hard to quantify. In practice, statistical relationships, along with standard deviation, between porosity and seismic properties need to be established for each facies in a reservoir.

Many reservoir sands and sandstones contain clays. The effect of clays on seismic properties depends further on the position of the clay particles in the rock and on the clay type. If the clays are part of the rock matrix and if the clays are more compressible than quartz, velocity and impedance will decrease

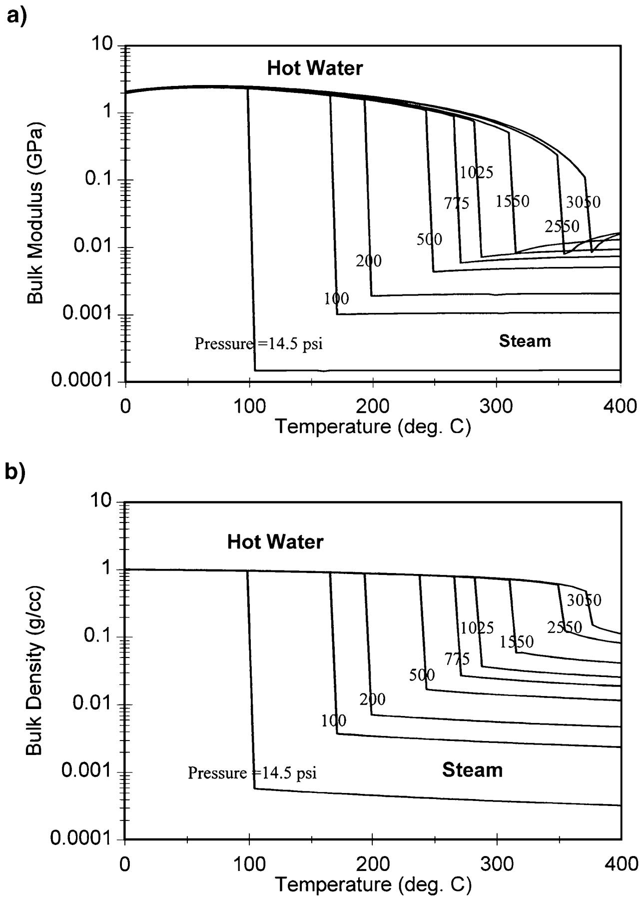

FIG. 2. Adiabatic bulk modulus (a) and density (b) of water and steam versus temperature and pressure. Both bulk modulus and density drop sharply as water transforms to steam.

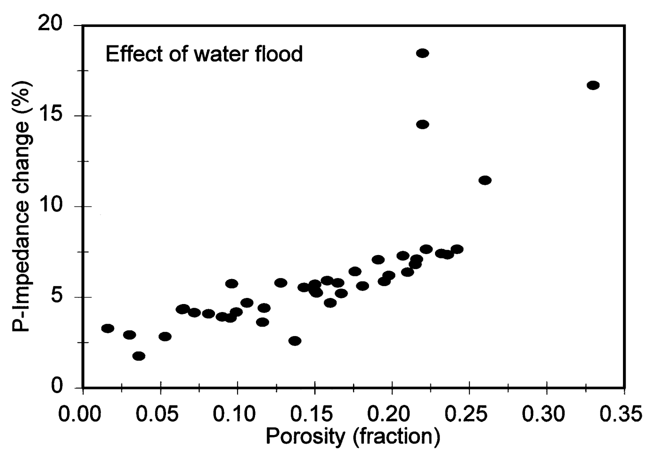

FIG. 3. P-wave impedance change as a result of water flood in 44 sandstone and sand samples versus porosity. Low porosity rocks, which tend to have hard elastic frames, show smaller effect of water flood on seismic impedances.

as clay content increases. Except for the density effect, pore-filling clays have little influence on seismic properties, unless the pores are completely filled. Tosaya and Nur (1982) were among the first to study the combined effects of porosity and clay content on seismic velocities. Han et al. (1986) extended this study and developed a set of empirical relations between velocity, porosity, and clay content that were based on laboratory measurements of about 80 sandstone samples. The relations take the linear forms

$$V_p = V_{po} - a_1\phi - a_2 C \tag{24}$$

and

$$V_s = V_{so} - b_1\phi - b_2 C, \tag{25}$$

where ϕ and C are porosity and clay content in volume fraction, respectively. V_p and V_s are compressional and shear velocities in km/s. The regression constants are functions of the net overburden pressure (Table 2).

Equations (24) and (25) clearly show that both V_p and V_s statistically decrease with increasing porosity and clay content. These relations take no account of the position of clay particles in the rock. They are only empirical, not necessarily physical. Eberhart-Phillips et al. (1989) further extended Han et al.'s (1986) regressions to include pressure. Castagna et al. (1985) reported relationships similar to equations (24) and (25), which they found from log data.

PRESSURE

In a reservoir, there always exist two distinct pressures: overburden pressure and reservoir pressure. The overburden pressure (P_o), also called confining pressure, is the pressure exerted by the total overburden rock strata, whereas the reservoir pressure (P_p), also called fluid pressure or pore pressure, is exerted by the fluid mass. The difference between the overburden pressure and reservoir pressure is called the net overburden pressure (P_d), which is also called differential pressure or sometimes effective pressure (P_e). Strictly speaking, $P_e \neq P_d$. In fact, $P_d = P_o - P_p$, whereas $P_e = P_o - nP_p$, where $n \leq 1$. It is the net overburden pressure that controls the seismic properties of reservoir rocks. This is because the pore fluid pressure supports a part of the overburden pressure, thereby decreasing the load supported by the total rock strata.

Seismic velocities and impedances, both P and S, increase as the net overburden pressure increases. The relationships between seismic properties and the net overburden pressure, however, is nonlinear: seismic properties increase faster (higher slope) in low net overburden pressure regions. As a result, knowing the reservoir pressure regime is very important in seismic applications such as 4-D and AVO. For example, Figure 4 shows the V_p versus net overburden pressure in a sandstone. Increasing the net overburden pressure from 1650 to 2650 psi causes a 5.2% V_p increase, whereas the same amount of net overburden pressure increase from 4500 to 5500 psi only results in a 0.5% V_p increase.

Table 2. Regression constants for equations (24) and (25).

Net pressure	V_{po}	a_1	a_2	V_{so}	b_1	b_2
Water saturated						
40 MPa	5.59	6.93	2.18	3.52	4.91	1.89
30 MPa	5.55	6.96	2.18	3.47	4.84	1.87
20 MPa	5.49	6.94	2.17	3.39	4.73	1.81
10 MPa	5.39	7.08	2.13	3.29	4.73	1.74
5 MPa	5.26	7.08	2.02	3.16	4.77	1.64
Air saturated						
40 MPa	5.41	6.35	2.87	3.57	4.57	1.83

During production and enhanced oil recovery (EOR) processes, both reservoir pressure and fluid saturation change. Pressure and saturation effects may reinforce or compete with each other. The resulting changes in seismic properties (velocities and impedances) depend on the combined effects of pressure and saturation changes. For example, in a water-drive process, water displaces oil so that oil saturation decreases. In the meantime, reservoir pressure may drop due to production, resulting in an increase in the net overburden pressure. Both decreases in oil saturation and reservoir pressure will increase the P-wave velocities and impedances so that the two effects reinforce each other. In contrast, in a water-injection process, the injected water displaces oil so that oil saturation decreases (water saturation increases), but the reservoir pressure is typically increased by water injection, resulting in a decrease in the net overburden pressure. Lower oil saturation would increase, but higher reservoir pressure would decrease the P-wave velocities and impedances. As a result, saturation and pressure compete with each other in this case, partially, or even totally, canceling each other's effect on seismic properties. These two examples illustrate the importance of understanding reservoir process and rock property changes in planning and timing 4-D seismic surveys.

TEMPERATURE

Seismic velocities and impedances decrease only slightly in rocks saturated with gas or water as temperature increases (Timur, 1977; Wang and Nur, 1990b). When a rock is saturated with oil, however, seismic properties may decrease by large amounts with increasing temperature, especially in unconsolidated sands with heavy oils. Such velocity dependence

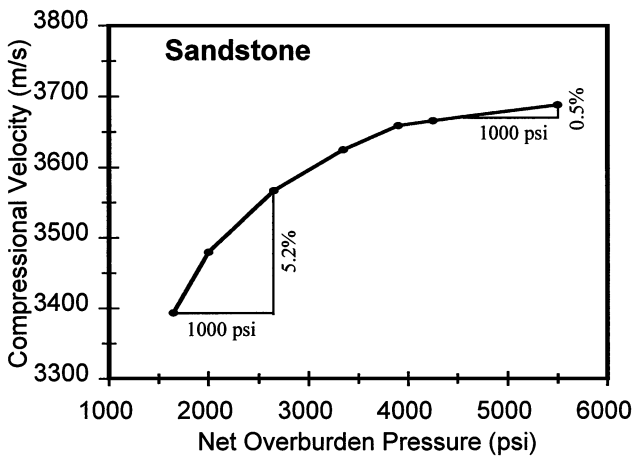

FIG. 4. V_p versus net overburden pressure in a sandstone. Increasing the net overburden pressure from 1650 to 2650 psi causes a 5.2% V_p increase, whereas the same amount of net overburden pressure increase from 4500 to 5500 psi only results in a 0.5% V_p increase.

on temperature in hydrocarbon-saturated rocks provides the physical basis for seismic monitoring of thermal EOR. Tosaya et al. (1987) first showed dramatic decreases of compressional velocities in heavy oil sands. As temperature increases from 25° to 125°C, V_p can drop by 35% to almost 90%! Such huge decreases are caused in part by the compressibility increases of the oil. Furthermore, part of the V_p decrease was caused by the abnormally high pore pressure in Tosaya et al.'s experimental setup: the oil inside the pore space expanded very fast when the core was heated up, yet the pore pressure tube was plugged by the cold viscous oil outside the pressure vessel. In spite of this, the magnitude of V_p decreases was so profound that further investigation was needed.

Wang and Nur (1990b) measured numerous heavy oil sands and hydrocarbon-saturated rocks. Their results show that both V_p and V_s decrease with increasing temperature. They avoided the overpressure problem in their experiments and found that V_p decreased by as much as 40% as temperature increased from 20° to 125°C.

Figures 5a and 5b show V_p and V_s, respectively, versus temperature in a heavy oil sand. In the experiments, V_p and V_s were measured as functions of temperature from room temperature (71°F or 22°C) to 350°F (177°C). In Figure 5a, V_p decreases by about 15% as temperature increases from 22° to 177°C. Figure 5b shows that V_s also decreases by around 15% as temperature increases from 22° to 177°C. Because V_s is theoretically not affected by fluids, the V_s decrease in Figure 5b is caused by changes in the rock frame and in the rock-fluid interactions. Because heavy oils are viscous, there exists a strong interfacial force between the oil and rock grains (one analogy is the asphalt used in road paving). As temperature increases, oil viscosity and the interfacial force decrease, loosening up the sand grains so that both the bulk modulus and shear rigidity decrease.

V_p shows a step drop between 120° and 177°C at low pore pressures (50 and 100 psi) as water inside the rock turns to steam (the top two curves), adding another 10% or so to the V_p decrease. In contrast, V_s increases by about 5% as a result of steam. The additional V_p decrease is caused by the higher compressibility of steam compared to that of hot water (Figure 2a). The V_s increase is caused by the bulk density decrease as steam displaces liquids out of the pore space due to volume expansion.

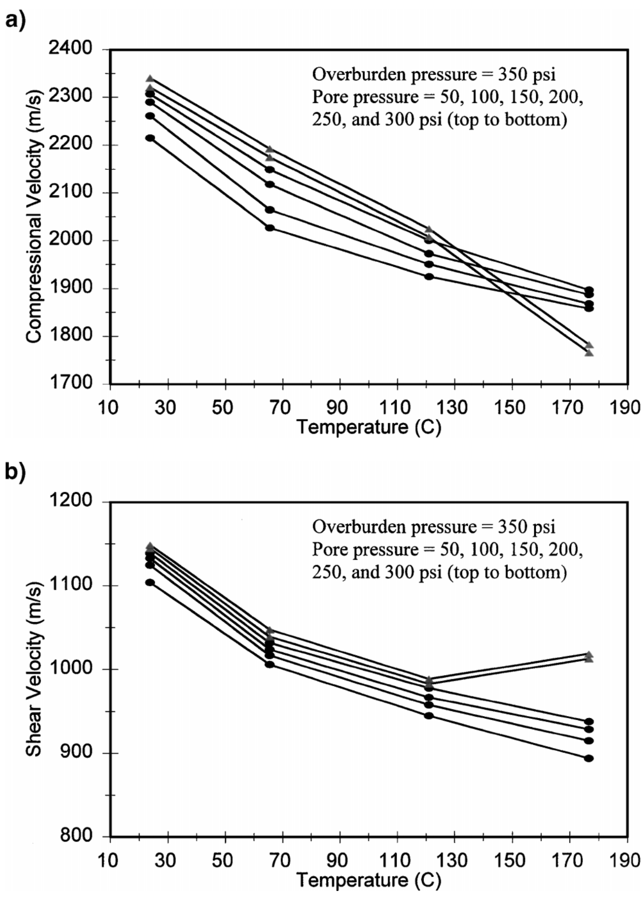

FIG. 5. V_p (a) and V_s (b) versus temperature in a heavy oil sandy. Both Vp and Vs decrease by about 15% as temperature increase from 22° to 177°C. V_p drops further between 120° and 177°C at low pore pressures (50 and 100 psi) as water inside the rock transforms to steam [the top two curves in (a)], adding another 10% or so V_p decrease. In contrast, V_s increases by about 5% as results of steam.

LITHOLOGY

For a given porosity and pore aspect ratio spectrum, dolomite has the highest V_p among reservoir rocks, followed by limestone, sandstone, and unconsolidated sand. The order is different in terms of decreasing V_s, with a possible order of sandstone, dolomite, limestone, and unconsolidated sand. Because of this, limestone has the highest V_p/V_s ratio, followed by dolomite, deeply buried unconsolidated sand, and sandstone. Shallow unconsolidated sands may have very high V_p/V_s due to poor grain contacts. But once the grains contact each other well under pressure, unconsolidated sands normally show lower V_p/V_s ratios than carbonates. The V_p/V_s ratio difference therefore provides a tool for lithology discrimination. Of course, both the velocity values and V_p/V_s are complicated by the pore aspect ratio spectrum, fracture alignment, pressure effects, etc.

Shales are reservoir cap rocks that have a wide range of velocities and impedances. However, shales always have higher V_p/V_s ratios than reservoir sands. As a result, when the cap shale and reservoir sands have similar P-wave impedances, their S-impedances are different. An example was shown by MacLeod et al. (1999) in Alba field, North Sea. Because of similar P-wave impedances between the cap shale and reservoir sand, streamer P-wave seismic data was inadequate for defining reservoir boundaries. But the S-wave impedance contrast at top of the reservoir is very large, resulting in successful reservoir imaging by use of P to S converted waves.

DENSITY

In theory, seismic velocities do not have to increase with bulk density. For example, anhydrite has a higher bulk density but a lower velocity compared to dolomite. Furthermore, increasing the bulk density by adding more water in a partially gas/water saturated rock will also decrease the velocities because the added water increases the bulk density but not the bulk modulus. Empirical relationships do exist that relate seismic velocity increases with increasing bulk density. One of these is Gardner et al.'s (1974) classic relationship:

$$\rho = 0.23V_p^{0.25}, \tag{26}$$

where V_p is the compressional velocity in ft/s and ρ is the bulk density in g/cm^3. Gardner et al.'s relationship, however, can only estimate compressional velocities from bulk densities in water-saturated sedimentary rocks. Although Gardner et al. did give separate curves for individual lithologies, equation (26) treats all sedimentary rocks as a single group, so that only a single $V_p - \rho$ relationship exists for all the sedimentary rocks.

Wang (2000b) also divided sedimentary rocks into several subgroups based on lithology and developed a set of relationships between bulk density and both V_p and V_s. These relationships are based on a large laboratory data set (over 500 data points) and hold for a variety of lithologies and saturations. Figure 6a shows that Gardner et al.'s (1974) relationship (dotted line) in general underestimates V_p in water-saturated reservoir rocks but overestimates V_p in water-saturated shales. Wang's (2000b) refined relationships (solid lines) work better if lithology is known. They also work for gas-saturated rocks. Figure 6b shows that systematic relationships also exist between bulk density and V_s. These results are similar to the findings of Castagna et al. (1993).

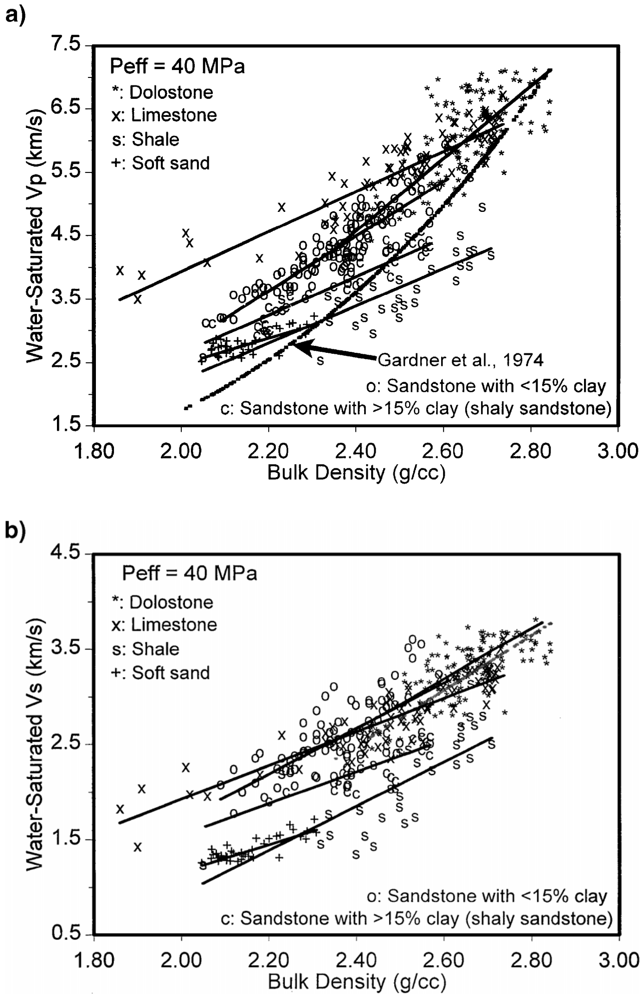

FIG. 6. V_p (a) and V_s (b) versus bulk density in sedimentary rocks. Gardner et al.'s (1974) relationship [dotted line in (a)] in general underestimates V_p in water-saturated reservoir rocks but overestimates V_p in water-saturated shales.

TEXTURE

Seismic properties are also controlled by texture such as grain-to-grain contacts, roundness, sorting, cementation, etc. Poor grain-to-grain contacts normally result in lower seismic velocities and impedances, whereas cementation increases seismic properties sharply. Large grain-size sands show higher seismic velocities compared to fine sands due to larger contact areas among grains. Poorly sorted sands show higher seismic velocities because poor sorting reduces porosity. Spencer et al. (1994) suggest that sorting and grain sizes of unconsolidated sands may affect both the V_p/V_s and Poisson's ratio in unconsolidated sands. The roundness or angularity of the sand grains may also affect seismic velocities and V_p/V_s: well-rounded grains lead to better grain contacts and hence higher velocities. Because textures of sedimentary rocks are difficult to quantify and cannot be described without cores, the effect of texture on seismic properties is in turn poorly quantified. Further investigation on this subject is needed.

COMPRESSIONAL VERSUS SHEAR VELOCITY

Although dipole sonic logs are nowadays commonly acquired in wells, the need to derive V_s from the available V_p is still routine due to the amount of existing legacy data in many developed fields where only monopole logs are available. Castagna et al. (1985) published an empirical relation that relates V_p to V_s velocities for water-saturated clastic silicate rocks. The correlation is known as the mudrock line:

$$V_p = 1.36 + 1.16V_s \text{ (km/s)}. \tag{27}$$

Although the mudrock line is useful in deriving shear velocities when other alternative correlations are unavailable, it suffers some obvious drawbacks: (1) it underestimates V_s with known V_p in soft unconsolidated sands and some clean lithified sands, and (2) it is valid only for water-saturated clastic rocks.

Krief et al. (1990) presented a model relating bulk and shear moduli in dry rocks to the Biot coefficient (Biot, 1941). For fluid-saturated rocks, the authors use the Gassmann equation (Gassmann, 1951) and give a straight-line relationship involving the squares of compressional and shear velocities in fluid saturated rocks:

$$\frac{V_{p,sat}^2 - V_f^2}{V_{s,sat}^2} = \frac{V_{p,m}^2 - V_f^2}{V_{s,m}^2}, \tag{28}$$

where $V_{p,sat}$ and $V_{s,sat}$ are compressional and shear velocities, respectively, in a fluid-saturated rock; $V_{p,m}$ and $V_{s,m}$ are compressional and shear velocities, respectively, in the rock's solid matrix (mineral); and V_f is the compressional velocity in the pore fluid.

Krief et al.'s (1990) model assumes that the frame V_p/V_s equals to the solid matrix's V_p/V_s. This is only approximately true for quartz sands and sandstones. As a result, equation (27) cannot be used for rocks other than sands and sandstones.

Greenberg and Castagna (1992) presented an iterative model for estimating shear velocity in porous rocks. The model combines the Gassmann equation and the Voigt-Reuss-Hill velocity average to yield shear velocity. The required input parameters to this model are lithology, saturation, porosity, and compressional velocity.

Murphy et al. (1993) observe that the frame shear to bulk modulus ratio is close to a constant value of 0.9 for quartz sands, which yields a constant V_p/V_s ratio of 1.55. Murphy et al. also give a set of relationships between frame bulk and shear moduli to porosity. For porosity less or equal to 0.35, the frame bulk and shear moduli are second-order polynomial functions of porosity:

$$K_d = 38.18(1 - 3.39\phi + 1.95\phi^2) \tag{29}$$

$$G_d = 42.65(1 - 3.48\phi + 2.19\phi^2). \tag{30}$$

For porosity greater than 0.35, the relationships become exponential:

$$K_d = \exp(-62.60\phi + 22.58) \tag{31}$$

$$G_d = \exp(-62.69\phi + 22.73), \tag{32}$$

where K_d and G_d are the bulk and shear moduli, respectively, of the frame rock (rock with empty pores)in GPa; ϕ is porosity in volume fraction.

When porosity, density, and shear velocity data are available, the shear modulus can be calculated with both $G_d = \rho V_s^2$ and equation (30) or (32). The two G_d values are then compared. If the two are close, the rock is a sand. If the calculated frame shear modulus with $G_d = \rho V_s^2$ is significantly lower than the G_d from equation (30) or (32), the rock is a shale.

Murphy et al.'s (1993) findings are comparable to Wang's (2000c) results, who used a larger data set: the frame shear to bulk modulus ratio averages 0.9639 for granular materials, sands, and sandstones. This corresponds to a frame V_p/V_s ratio of about 1.54 (Poisson's ratio is 0.135). Figure 7 shows that, in general, a linear relationship exists between the frame bulk (K_d) and shear (G_d) moduli in clastic granular rocks. This also agrees with Castagna et al. (1985), who found that the frame bulk and shear moduli are approximately equal to each other in clastic rocks.

V_p/V_s RATIO

It has been long recognized that V_p/V_s can be used as a lithology indicator (e.g., Tatham, 1982; Domenico, 1984). Shales, if assumed isotropic, always have higher V_p/V_s ratios than reservoir sands. In carbonates, Rafavich et al. (1984) showed that V_p/V_s could be used to discriminate limestones from dolomites. Wilkens et al. (1984) showed that V_p/V_s could be a good discriminant of mineral composition for siliceous limestones. Wang and Szata (1999) presented data showing that nonporous limestones and porous dolomites in an off-reef setting could have similar impedances but distinct V_p/V_s or impedance ratios. Figures 8a and 8b show their results, namely the impedance ratio versus P- and S-wave impedance, respectively. A clear separation exists between the reservoir (porous dolomite) and nonreservoir (nonporous limestone) rocks. Wang and Szata's rock physics results led to a successful field trial with multicomponent seismology, whose objective was to discriminate porous reservoir dolomites from nonporous limestones.

V_p/V_s or impedance ratios have also been used successfully for direct hydrocarbon detection, especially with AVO techniques. Because shear waves are insensitive to fluid changes, while compressional waves are, changes in fluid type and saturation will result in V_p/V_s changes. For a comprehensive review of this subject, see Castagna and Backus (1993).

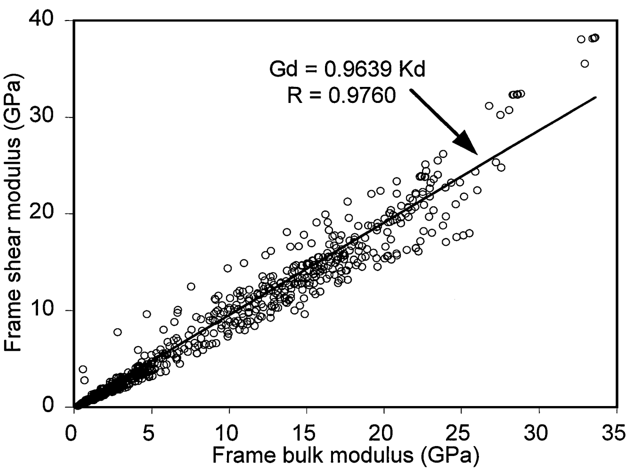

FIG. 7. A linear relationship exists between the frame bulk (K_d) and shear (G_d) moduli in clastic granular rocks. R is the correlation coefficient.

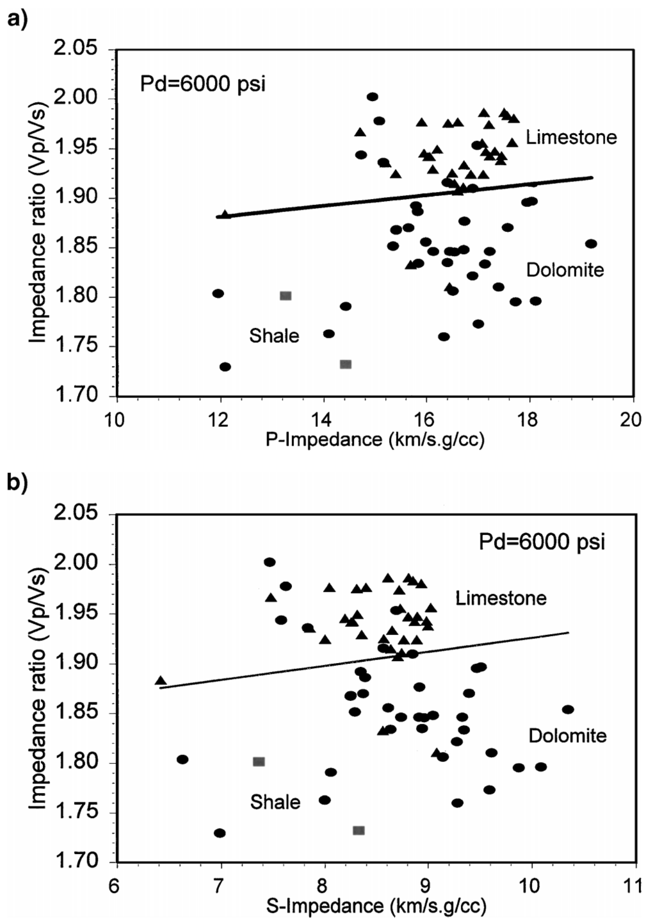

FIG. 8. Impedance ratio versus P-wave (a) and S-wave (b) impedance in carbonate rocks. A clear separation (solid line) exists between the reservoir (porous dolomite) and nonreservoir (nonporous limestone) rocks. P_d is different pressure (net overburden pressure).

ANISOTROPY AND SHALE PROPERTIES

Many hydrocarbon reservoirs are relatively deep, ranging from a few hundred to a few thousand meters in depth. This means that thick nonreservoir formations can overlie reservoir rocks. Furthermore, many hydrocarbon reservoirs are sealed by massive, impermeable shales that are intrinsically anisotropic. Seismic waves travel through these overburden rocks before reaching the reservoir. An understanding of the overlying shale properties and anisotropy is therefore important for seismic imaging. Migration result of a Gulf Coast seismic section that accounts for anisotropy shows much sharper images of the reservoir and faults, as compared to migration without taking anisotropy into account (Meadows and Abriel, 1994). Until recently, however, rock physics data on seismic velocities and anisotropy in shales have been scarce, largely due to the time-consuming nature of laboratory measurements of shales. Because at least five independent measurements are needed to describe a transversely isotropic (TI) medium, three separate, adjacent core plugs are traditionally required.

Two types of anisotropy exist in rocks: intrinsic anisotropy and induced anisotropy. Intrinsic anisotropy is caused by the preferential alignment of elongate grains or pores and fine lamination. Intrinsic anisotropy in sedimentary rocks is normally in the form of transverse isotropy, so that five independent elastic constants are needed to describe the elastic properties of the rocks. Most shales are intrinsically transversely isotropic. Kaarsberg (1959) was probably the first to study the sonic properties of shales. Later on, many authors presented results on shale properties and anisotropy based on limited amounts of data (e.g., Jones and Wang, 1981; Tosaya, 1982; Lo et al., 1986; Vernik and Nur, 1992; Hornby, 1994; Johnston and Christensen, 1995; Vernik and Liu, 1997). All the measured shales show a substantial degree of seismic anisotropy, ranging from a few percent to as high as 50%.

Induced anisotropy is caused by stress anisotropy and fracturing. Nur and Simmons (1969) were the first to study stress-induced anisotropy. Stress anisotropy preferentially aligns pores, grains, cracks, and fractures so that an otherwise isotropic rock becomes seismically anisotropic.

Figure 9 shows the measured compressional and shear velocities in a brine-saturated soft shale. The compressional and shear velocities show about 20% and about 15% anisotropy, respectively. From many laboratory measurements of shale anisotropy, I have seen as much as 50% velocity anisotropy in both P- and S-waves. Obviously, such high magnitude of anisotropy cannot be neglected in seismic processing and interpretation.

SUMMARY: ROCK PHYSICS RULES OF THUMB

Although rocks are extremely complicated, their seismic properties (V_p, V_s, and impedance) depend largely on a combination of connectivity and elasticity and density of what is connected. As a result, many rules of thumb can be explained by such combinations. For example, dolomite has a high bulk modulus and the individual "grains" are well connected in a dolomite rock, so that compressional velocity and impedance are high. Compared to dolomite, quartz has a lower bulk modulus and the grains are not as well connected, resulting in lower compressional velocities in sandstones. For shear waves, quartz and dolomite have a similar shear modulus, but dolomite is denser, resulting in lower V_s in pure dolomite compared to solid quartz. However, because of the poor connectivity of quartz grains, sandstones normally have lower V_s than dolomite.

In seismic applications of rock physics, I have been frequently asked for rules of thumb such as "Which way does V_p go, and by how much, if reservoir pressure increases?", etc. Because rocks are so complicated and heterogeneous microscopically, these rules of thumb only work in a general sense. The magnitude of change in seismic properties in response to changes of a petrophysical parameter varies from rock to rock. As a result, the rules of thumb presented here are only qualitative.

Table 1 shows some of the factors influencing seismic properties of sedimentary rocks. These factors are grouped in three categories: rock properties, fluid properties, and environment. Elaborations can be found in Tables 3, 4, and 5. The list is comprehensive, but by no means complete. Most of these factors also interact with each other; it is likely that changing one factor would change several others. For purposes of clarity, each factor is discussed separately in Tables 3, 4, and 5, so that other factors are assumed to remain constant. In practice, one should be aware of the interactions among these factors.

DISCUSSION

Although impressive headway has been made in recent years in the understanding of the physical properties of rocks and in the application of this knowledge to seismic monitoring, to direct hydrocarbon detection, to lithology, fluid, and porosity inversion, and to seismic interpretation, there are still many unsolved problems.

Know the range of applicability before using a theory or empirical equation

Because rocks are so complicated and variable from field to field, a universal rock physics theory or empirical relationship is impossible to obtain. When theories and models are used, one has to be aware of their range of applicability and the

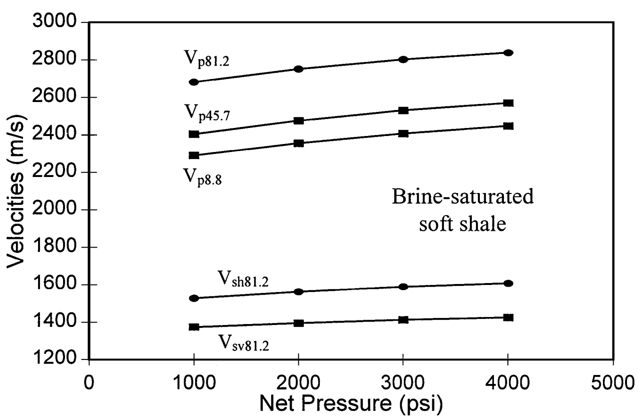

FIG. 9. Measured V_p and V_s in a brine-saturated soft shale. Three V_p s were measured at propagation directions of 81.2°, 45.7°, and 8.8° to the symmetry axis. Two shear velocities were measured at a propagation direction of 81.2° to the symmetry axis (the SH- and SV-waves are polarized at 81.2° and 8.8° to the symmetry axis, respectively).

Table 3. Rock physics rules of thumb, I: Relations between seismic properties and rock properties.*

Compaction	Better compacted rocks have higher seismic properties (compressional and shear velocities and impedances) due to better connectivity/contact.
Consolidation	Better consolidated rocks have higher seismic properties due to better connectivity/contact.
Age	Older rocks have higher seismic properties due to better compaction.
Cementation	Cemented rocks have higher seismic properties due to better connectivity and contacts among grains.
Texture	Texture includes grain size, sorting, roundness, etc. In general, sands with larger grain size and sands with poorly sorted grains have higher seismic properties due to better contacts and lower porosity. Sands with angular grains have lower seismic properties but higher V_p/V_s compared with sands composed of spherical grains.
Bulk density	Statistically, rocks with higher bulk density have higher seismic properties.
Clay content	The effect of clay on seismic properties depends on the position of the clay particles inside the rock. Statistically, rocks with higher clay content have lower seismic properties and higher V_p/V_s.
Anisotropy	Two types of anisotropy exist: intrinsic and induced. Almost all shales are intrinsically anisotropic. A good approximation of shale anisotropy for flat layers is vertical transverse isotropy. Older, consolidated shales usually have higher degree of seismic anisotropy. Stress anisotropy is the major cause of induced anisotropy. Most reservoir rocks can be approximated being intrinsically isotropic unless they are finely layered.
Fractures	Fractures cause seismic properties to decrease. Compressional properties are affected much more by fractures compared to shear properties when the waves are polarized across the fractures. Waves polarized perpendicular to a fracture have low V_p/V_s. Aligned fractures also cause seismic anisotropy.
Porosity	Statistically, seismic properties decrease as porosity increases. V_p/V_s is normally not a strong function of porosity.
Lithology	Dolomite has high seismic properties, followed by limestone and sand. Shales may have higher or lower seismic properties than sands. Limestone has high V_p/V_s, followed by dolomite and sands. Shales always have higher V_p/V_s than sands. Uncompacted sands may also have high V_p/V_s.
Pore shape	Pore shape is the most important factor influencing seismic properties yet is the hardest to quantify. In general, rocks with flat pores have lower seismic properties. Pore shape difference is the major cause of scatter in velocity-porosity plots.

*Seismic properties increase with the elasticity and the micro-connections in the rock. Note that each factor is assessed independently here assuming others are constant. In reality, many of these factors interact.

Table 4. Rock physics rules of thumb, II: Relations between seismic properties and fluid properties.*

Viscosity	Rocks with more viscous oil tend to have higher seismic properties. When the oil's viscosity is extremely high, the oil may act as a semisolid in the rock, resulting in higher seismic properties.
Density	Higher density oils have higher bulk moduli (lower compressibilities). As a result, rocks with higher density oils have higher compressional properties and shear impedance, but shear velocity may be lower.
Wettability	Wetting changes the interfacial energy between the rock and the saturating fluid (the interfacial forces are attractive between the wetting fluid and the solid surface and repulsive between a nonwetting fluid and the solid surface). A rock fully saturated with a nonwetting fluid has slightly higher seismic properties compared with the same rock saturated with the same but wetting fluid. Most sands are water wet, so seismic properties decrease when water is added to a dry rock (softening effect).
Fluid composition and type	Heavier oils contain higher carbon-number hydrocarbons so that their bulk moduli are higher. As a result, rocks saturated with heavier oils show higher compressional properties. Shear properties are much less affected with shear impedance being slightly higher and shear velocity being slightly lower. In general, high salinity brine has the highest bulk modulus, followed by low salinity brine, fresh water, oil, and gas. But some heavy oils may have a bulk modulus as high as, or even higher than, water's.
Fluid phase	Rocks saturated with fluids in their gaseous phase (hydrocarbon gas, steam, CO_2 gas) have lower compressional seismic properties and shear impedances but slightly higher shear velocities due to the fluids' higher compressibility and lower bulk density, resulting in lower V_p/V_s in the rocks. Seismic properties hardly depend on the amount of gas when gas saturation is between 5 and 100%.
Gas-oil and Gas-water ratios	The larger the amount of gas dissolved in an oil, the lower bulk modulus of the oil has. Some high gas-oil-ratio (GOR) oils act like gas seismically, resulting in "bright spots" at oil-water contacts. Rocks saturated with high GOR oils have lower compressional seismic properties compared to the same rocks saturated with gas-free oils. Gas dissolved in water has little effect on the bulk modulus because of the unique molecular structure of water. Little gas can be dissolved in water anyway.
Saturation	Full saturation of a liquid in a rock increases the compressional seismic properties and shear impedance but decreases V_s, resulting in increases in V_p/V_s. When gas is introduced to a fully liquid-saturated rock, the compressional seismic properties and shear impedance all decrease but V_s increases, resulting in lower V_p/V_s. The magnitude of saturation effect is higher in rocks with weak frames and/or flat pores (cracks, fractures).

*Rocks with more incompressible or viscous fluids have higher compressional properties. Shear properties in rocks are much less sensitive to fluid saturation. Note that each factor is assessed independently here assuming others are constant. In reality, many of these factors interact.

Table 5. Rock physics rules of thumb, III: Relations between seismic properties and environment.*

Frequency	Normally, seismic properties are higher at high frequencies (dispersion). However, the magnitude of dispersion is hard to assess due to difficulties in measuring seismic properties as functions of continuous frequency across seismic (10–200 Hz), log (around 10 kHz), and lab frequency (100 kHz–2 MHz) bands.
Stress history	Knowing stress history of a rock under measurements can help plan the measurements and interpret the data. Hard rocks are usually brittle. If a rock was under great stress, the relief of stress generates microcrocks in the rock, which reduces seismic velocities. Simply restoring the rock to the original stress may or may not eliminate the induced microcracks. The stress relief-induced microcracks may help identify the maximum/minimum horizontal stress directions in situ.
Depositional environment	Depositional environment variously affects seismic properties. For example, authigenic and detrital clays affect seismic properties differently. The rate and source of deposition and depositional energy also affect seismic properties (e.g., sand/shale sequences are results of alternating depositional energy, rate, and source).
Temperature	Seismic properties decrease as temperature increases. Dry (empty pores) and water-saturated rocks normally show small seismic property decreases as temperature increases. However, rocks, especially soft sands, saturated with heavy oils show large seismic property decreases as temperature increases.
Reservoir process	In seismic reservoir characterization and 4-D seismic reservoir monitoring, it is paramount to understand the reservoir process. For example, waterflood increases water saturation and pressure in a reservoir. It may also decrease the temperature slightly. In general, the effect of reservoir process on seismic properties is a combination of several factors. These factors may cancel or enhance each other's effect on seismic properties.
Production history	The effect of production history is similar to that of reservoir process on seismic properties. In seismic reservoir characterization, production data and reservoir parameters (fluids, saturation, pressure, temperature) need to be carefully gathered at the time of the seismic survey in order to better interpret the seismic data.
Net reservoir pressure	Net reservoir pressure is the difference between overburden and reservoir pressures. Because overburden pressure does not change (or changes very little) in a reservoir, the effect of net reservoir pressure is just the opposite of the effect of reservoir pressure on seismic properties. Seismic properties in all rocks increase as net reservoir pressure increases. The magnitude of such an increase depends on several other factors (pore shape, porosity, pore fluids, lithology, etc.). It can only be quantified through measurements.

*Pressure, temperature, and history (both depositional and production) all affect the current state of the rock. Note that each factor is assessed independently here assuming others are constant. In reality, many of these factors interact.

assumptions. Whenever a theory is stretched outside of its range of applicability and its assumptions are violated, erroneous results are generated and in turn seismic data are misinterpreted. One typical example is the misuse of Wyllie et al.'s (1956) time-average equation to calculate the effect of gas saturation on seismic velocities (the time-average equation was derived for liquid-saturated rocks). On the other hand, empirical equations are often generated from a specific data set within certain pressure, temperature, saturation, etc., ranges Beyond the data set and its physical range, empirical equations should be used with great caution.

Use rock physics data and knowledge whenever possible

Although rock physics has played fundamental roles in developing seismic technologies such as 4-D seismology, AVO, rock property inversions, etc., it has been underused in interpreting seismic data. With ever-increasing computing power and constantly improving seismic processing technologies, I believe that seismic data are going to be interpreted in more and more detail for lithology and pore fluid discrimination, porosity inversion, and extraction of reservoir parameters such as pressure and temperature. Without rock physics, these tasks would be hard to achieve. However, the challenge is that quantitative interpretation needs large amounts of rock physics data to yield statistical relationships and to decouple the combined effects of reservoir properties and parameters. Although skilled laboratory measurements seem to be relatively expensive for large amounts of data, the potential cost savings and economic benefits of a more quantitative seismic interpretation could be enormous.

True magnitude of dispersion is still unknown

One of the daunting issues in rock physics is frequency and dispersion. The Gassmann (1951) equation is an inherent zero-frequency theory. Although Biot's (1956a, b, 1962) theory incorporates frequency effects, it is inadequate to account for the overall dispersion in rocks (Winkler, 1985; Wang and Nur, 1990a). Depending on the pore structure and fluid viscosity, seismic frequencies may well be considered in the high frequency range relative to the Gassmann equation. Due to experimental difficulties, the Gassmann equation has not been rigorously verified in the laboratory or in the field. Furthermore, there exist many so-called high-frequency theories in the literature that should be used with great caution. In essence, knowing the assumptions and limitations of the theories, models, and equations is paramount in order to produce meaningful results.

While Biot's theory considers only the effect of large-scale fluid flow (regional flow) on seismic wave dispersion, the local flow model (Mavko and Nur, 1975; O'Connell and Budiansky, 1977) considers the small, pore-scale squirt flow. The two mechanisms in combination seem to explain well the fluid flow effect on seismic wave dispersion. In practice, seismic data gathered at 10–200 Hz are close to the Gassmann results for high-porosity, high-permeability rocks saturated with low-viscosity fluids. For low-porosity, low-permeability rocks saturated with high-viscosity fluids, data gathered at seismic frequencies are close to log- or lab-measured data (Wang, 2000a). However, the true magnitude of wave dispersion in fluid-saturated rocks will remain unknown until several technical problems can be solved. For details on velocity dispersion and frequency effects, see the collection of papers in Nur and Wang (1989) and Wang and Nur (1992, 2000).

Scale up by adequate sampling

Another issue in rock physics is the scaling effect: laboratory-measured rock physics data only represent properties of a tiny portion of the hydrocarbon reservoir. Rocks are known to be heterogeneous, especially at core scales. One solution to this scaling problem is that laboratory measurements should not focus on a few samples. Instead, laboratory samples should be carefully selected to represent facies, depositional sequences, lithology types, etc. A sufficient number of samples should be measured to derive statistical relationships between seismic and reservoir properties. Such statistical relationships effectively scale up core data to the seismic scale. It is these statistical relationships, not the individual values or numbers, that should be used in seismic modeling and interpretation.

In thin-bed or sand-shale sequence reservoirs, thin beds may remain below seismic resolution. In this case, cores should be again adequately sampled. Once the representative properties of each thin bed are obtained, Backus (1962) averaging can be used to scaleup the lab or log data.

Because rock physics connects reservoir properties and parameters to seismic data, it plays a fundamental role in many technologies attempting to derive reservoir rock and fluid properties and reservoir parameters from seismic data. With more and more fields maturing and technologies further improving and progressing, it is conceivable that one day seismic surveys will be routinely used in taking three-dimensional snap shots of reservoirs for mapping porosity and fluid flow, diagnosing reservoirs for pressure, temperature, saturation changes, and even inferring hydrocarbon types. During such a process, rock physics will be an essential component for quantitatively interpreting seismic data and for unraveling the superposed effects of reservoir changes on seismic data.

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