ACOUSTIC CORE ANALYSIS IN RESERVOIR APPRAISAL

W. Keith Hirsche, Zhijing Wang* and George Sedgwick**
Western Geophysical, Isleworth, U.K.
* Chevron Oil Field Research Co., La Habra Ca., U.S.A. (formerly Core Laboratories Canada)
** Alberta Research Council, Edmonton, Canada

Abstract Acoustic velocity measurements from core samples can play an important role in correlating seismic velocities to underlying reservoir properties. Seismic velocity in reservoir rocks is most directly affected by lithology, porosity, confining pressure, and pore saturant. Unfortunately, the relationship between velocity and each of these variables is non-unique. This uncertainty limits the geophysicist's ability to map reservoir properties from seismic data and complicates the use of sonic logs in petrophysical analysis. Laboratory experiments provide a controlled environment where the relationships between acoustic velocity and petrophysical parameters can be independently studied.

We have recently completed a research project focusing on the acoustic properties of carbonate cores. Laboratory experiments were designed to measure the acoustic velocity sensitivity to changes in porosity, net confining pressure and pore saturant. As expected, porosity correlates negatively with acoustic velocity, with correlation coefficients of -0.72 in gas saturated samples, and -0.84 in oil saturated cores.

Increasing effective confining pressure from 6.9 to 34.5 MPa resulted in increases in compressional velocity from 2% to 35% in gas saturated cores, and 1% to 19% after oil saturation. Shear wave velocities were slightly less sensitive to pressure with maximum changes of 26 %, and 22% in gas and oil saturated cores respectively.

Velocity sensitivity to pore fluid saturation was highly variable in the carbonate samples tested. Saturating the gas-filled cores with a 35 degree API mineral oil caused compressional velocity increases from 2% to 35%. These velocity changes decreased with increasing confining pressure. Average saturation-induced velocity increases were 13% at 6.9 MPa, 7% at 20.7 MPa and 6% at 34.5 MPa. Differences between oil and water saturated compressional velocities were usually less than 3%. Shear wave velocities were not strongly affected by changes in pore fluid saturation, as predicted by theory.

Laboratory experiments provide a means to separate the inter-related effects of pressure, porosity, and pore fluid saturation in the velocity data. Porosity is well correlated to seismic velocity if saturations and rock type are constant. Predicting pore fluids from seismic data will be complicated by the different magnitudes of saturation sensitivity among carbonate rocks. A thorough understanding of the effects of these factors on acoustic velocity is needed to properly interpret seismic data for use in reservoir characterization and appraisal.

INTRODUCTION

Seismic techniques were once used only for locating favourable structures for drilling, but with the advent of three-dimensional (3D) imaging, they are finding increased application in the characterization and description of hydrocarbon reservoirs. Several papers have been published that demonstrate the value of seismic data in porosity interpolation (eg. Doyen,1988), lithology mapping (eg. Doyen et al,1988), pore fluid identification (eg. Ensley,1983) and pore pressure mapping (eg. Paul,1990). Since seismic waves primarily respond to changes in the subsurface acoustic impedance (product of velocity and density), all seismic methods exploit relationships that exist between the parameter of interest, eg. porosity, and the acoustic parameters. Most of these relationships were initially developed or tested using laboratory measurements of acoustic velocity on clastic core samples. The laboratory measurements were instrumental because the parameters of the rock could be independently varied and measured, unlike field measurements where saturation, pore pressure, lithology and porosity are all varying at the same time.

Insight, gained in the laboratory, into the factors affecting acoustic impedance furnishes a basis for understanding the seismic response in complex reservoir conditions. Some early papers documenting the acoustic response to changes in porosity, clay content, saturation and pressure in clastic rocks have laid a foundation for the interpretation of wireline log acoustic data, and detailed seismic analysis. Our paper documents a major research effort into the acoustic behavior of limestone and dolomite reservoir rocks.

EXPERIMENTS

Apparatus

Velocities were measured through cores using the pulse transmission technique. The acoustic test apparatus is typical of this type of system, and comprises both a mechanical and electronic package (Figure 1). The mechanical components create the "reservoir condition" environment for the tests. They include a pressure vessel, pumps, a back pressure regulator, heaters and temperature controllers. The electronic system consists of a pulse generator, piezoelectric transmitting and receiving crystals, digital oscilloscope, and a computer with graphics printer.

Velocity measurements are made by generating a high voltage pulse that is converted by the transmitting crystal to a 500 kHz acoustic waveform which travels through the core until it is converted back to an electronic signal by the receiving crystal. The electronic waveform is then digitized by the oscilloscope and transferred to a microcomputer for processing and analysis.

Experimental Procedure

Acoustic velocity was measured as a function of saturation and pressure on more than 100 carbonate core samples. Cores were cleaned in a toluene extractor, then dried in a humidity- and temperature-controlled oven prior to initial velocity measurements. The samples were then loaded into the acoustic testing apparatus and evacuated. Compressional and shear wave velocities were measured as a function of net confining pressure (confining pressure less pore pressure). Most samples were then saturated with mineral oil. However, some samples were saturated initially with a brine solution, and then were flooded to residual water saturation using the mineral oil. These samples were intended to provide some control on the effect of wettability. Velocities were measured again, as a function of pressure, after oil saturation to determine the velocity contrast from gas to liquid saturation. Following these measurements, pentane, and a hydrocarbon miscible solvent were flooded through the core to displace the oil. Finally, several pore volumes of water were injected into the core to displace the hydrocarbons. Velocities were recorded at each of these saturation conditions.

Rock and Fluid Properties

Rocks

Samples were selected from a wide variety of carbonate depositional and diagenic environments. More than 100 cores were chosen to represent the wide variety of facies and texture types that categorize the carbonate reservoirs of the Alberta basin in Western Canada. Porosity fraction of the samples ranged from

0.02 to 0.21, with permeability varying from 0.2 to 3800 mD. The majority of the tests were conducted on 3.8 cm. diameter plugs, except when pore systems could not be represented at that scale and then full diameter (8.8 cm) cores were used.

Fluids

Air, Carnation oil, pentane, hydrocarbon solvent and fresh water were used as pore saturants in the experiments. Air was used to simulate natural gas. Carnation oil is a non-polar, white mineral oil with an API gravity of 35 degrees. The hydrocarbon solvent had a composition of 45% methane, 20% ethane, 20% propane and the remaining 10% consisting of components ranging up to heptane. Physical properties of the pore fluids are listed in Table 1.

EXPERIMENTAL RESULTS

The following sections report on the velocity response of the carbonate cores to changes in effective pressure, porosity, and saturation. Many of the observed results can be interpreted as pore geometry effects, and this will be discussed in the subsequent theoretical analysis section.

Influence of Effective Pressure on Acoustic Velocity

Effective confining pressure (Pe), or the difference between external confining (Pc) and pore pressure (Pp), strongly affects acoustic velocity (Hicks and Berry,1956; Wyllie et al,1958). We varied Pc and Pp indendently on several samples and found that P wave velocity was strictly a function of effective pressure (Pc-Pp) in the carbonate cores. Unfortunately, we did not measure shear wave velocities during this portion of our experiments, but King (1965) showed that this same conclusion should apply to shear waves. It is interesting to note that, unlike results from clastic samples, velocity hysteresis was not observed during pressure cycling. This is probably due to the more elastic nature of carbonate rocks.

Increasing effective pressure resulted in increases in both P and S wave velocities. Compressional velocities in gas saturated samples are most affected by pressure, with velocities increasing from 2% to 35 % when Pe was changed from 6.9 to 34.5 MPa (Figure 2). This velocity change is not linear, and the most rapid increases were observed from 6.9 to 20.7 MPa. Compressional velocities in saturated cores are less sensitive to pressure, with the largest velocity increase being 19% (Figure 3). Intuitively, one would expect that higher porosity rocks would be more sensitive to changes in effective pressure, but the experimental data show no correspondence between the magnitude of the velocity change and porosity.

Several recent publications have shown the value of seismic velocities in detecting overpressured zones prior to drilling. In some cases, it appears that this technique will be extendable to carbonates, as changes in pore pressure clearly cause velocity to decrease . Unfortunately, this type of application may be restricted to shallow depths (less than 2 km) because the velocity vs pressure gradient becomes insensitive at higher confining pressures.

Influence of Porosity on Acoustic Velocity

Sonic log interpretation, and seismically assisted porosity mapping are based on an underlying relationship between acoustic velocity and porosity. Compressional and shear wave velocities decrease as porosity increases. This correlation is not as pronounced in carbonate rocks as in sandstone formations (Domenico,1984) and it also varies with saturation and confining pressure (Figure 4). The correlations are most pressure sensitive for P-wave velocities in gas-filled samples, with correlation coefficients of -0.57, -0.67,-0.77 for effective pressures of 6.9, 20.7, and 34.5 MPa respectively. The P-wave correlations are higher, and less pressure dependent in oil-saturated samples, with values of -0.79, -0.81, and -0.83 for the same pressures. We found shear wave correlation coefficients were not strongly affected by changes in either saturation or pressure.

Figure 5 illustrates the porosity-velocity correlation coefficients as a function of wave type, lithology, and saturation for a constant pressure of 20.7 MPa. It is interesting to note that velocities in limestones exhibit higher correlations for all wave types and saturations than the corresponding dolomite values. This is not caused by "secondary porosity" effects, since a large percentage of the limestones were classed as vuggy, while a similarly large portion of the dolomites had only inter-crystalline porosity. When correlations are derived for the entire sample set, without segregating lithologies, they improve slightly. This seems to suggest that porosity estimation by acoustic techniques is not improved by separating lithologies.

When correlation coefficients are low there is a large uncertainty in porosity estimates made from sonic log or seismic data. For example, a P-wave velocity of 5.5 km/sec observed in a carbonate gas reservoir at 2 km depth (20.7 MPa Pe) could correspond to a porosity fraction anywhere between 0.05 and 0.15, while that same measurement could only represent porosities of 0.09 to 0.15 if the rock was oil-saturated.

Effect of Saturation on Acoustic Velocity

Rafavich et al (1984) found no statistically significant velocity dependence on pore-fluid saturation in their study of carbonate cores from the Mission Canyon Formation. While about 25% of the samples we tested duplicated their results, we observed a strong correlation between pore fluid saturation and compressional velocity in the majority of the cores that we measured. Velocity sensitivity did not correlate with porosity, as shown in Figure 6, but each porosity range contained rocks of high- and low-contrast behavior. Increasing the confining pressure decreased the overall sensitivity to saturation change

(Figure 7). When the gas-filled cores were initially saturated with oil the velocities increased from 1.5% to 27% (average 13%) at 6.9 MPa, 1.4% to 18% (average 7%) at 20.7 MPa and 0.7% to 12.5% (average 6%) at 34.5 MPa. Shear wave velocities were relatively insensitive to pore fluid saturation, changing from -3% to 6% at 20.7 MPa.

When oil was displaced by hydrocarbon solvent the velocities decreased from 1.5% to 14.5% (average 7%) at 20.7 MPa. Contrasts were pressure-dependent again, larger at lower pressure with decreases of 2% to 24% (average 12%) at 6.9 MPa, and 0.7% to 16% (average 4.5%) at 34.5 MPa.

Water was finally used to displace solvent from the cores. Velocities generally returned to, or slightly exceeded, oil-saturated values after water-flooding. All of the measured cores showed velocity differences between -1% and 3% between the oil-saturated and water-flooded conditions. This result was expected because of the similar acoustic properties of Carnation oil and water.

THEORETICAL ANALYSIS

Porosity, saturation, and pressure changes all affect velocity, but the sensitivity to each of these factors varies greatly from rock to rock. We attribute this result to the varying presence of micro-cracks and elongated, low aspect ratio pores. Wyllie et al (1958) attributed the large effect of pressure on velocity to the presence of cracks and flaws in the rock matrix which were closed at elevated pressure. Nur and Simmons (1969) built upon work by Walsh (1965) to expalain the role of micro-cracks in the interpretation of their laboratory results. They show that the greatest contributing factor to the overall compressibility of a gas-saturated rock is the presence of cracks, which are structurally weak and therefore close under pressure. When these cracks are filled with a relatively incompressible fluid, like water or oil, they become rigid and compressional velocity through the sample increases dramatically. We follow the work of Nur and

Simmons, and later Toksoz et al (1976), and interpret many of our results as pore aspect ratio phenomena. To support this conjecture we have analyzed our data using time-average, Gassmann, and Toksoz methods.

Time Average Analysis

The time-average method (Wyllie et al,1956) has formed the basis for porosity analysis from acoustic wireline logging data. This interpretation technique assumes that the transit time, or reciprocal velocity, through a formation is the porosity-weighted sum of the transit times in the rock matrix and pore fluid. We used the time-average equation to predict oil-saturated velocities for our carbonate database, and in Figure 8 we compare these predictions with the experimental results. The time-average technique consistently under-predicts the velocities that were measured in the cores, and this suggests that porosities computed using the relationship will be lower than the true values. We believe that these results demonstrate that the wavefield propagation model used in the equation is not applicable to carbonate rocks. Errors in porosity prediction from sonic data can be minimized by choosing artificially large matrix or fluid velocities that will distribute the error evenly on both sides of the prediction line. This effect is commonly noted in log interpretation handbooks (Schlumberger,1986; Dresser Atlas,1984) but the relatively low correlation between P-wave velocity and porosity will often result in questionable results.

Wyllie et al (1958), recommended measuring core velocities at high pressures in order to remove the influence of micro-cracks within the rock that are not modelled with the technique. We have already noted that the correlation between porosity and velocity does improve at higher effective pressures, especially in gas saturated samples, in accordance with this recommendation.

Gassmann Equation

We calculated saturated velocities using the Gassmann equation (Gassmann,1951) to analyze our experimental results. In general, the predictions agreed very well with the experimental results, with an average error of only 2% (Figure 9). This suggests that the Gassmann equation models acoustic behavior in carbonates more closely than the time-average method. Detailed examination of the results obtained at 20.7 MPa show that about 30% of the predictions slightly overestimate the measured results, while another 30% underestimate the observed saturation change. It is interesting to note that the equation, which was determined for a low frequency solution, sometimes overestimates the velocities measured at ultrasonic frequencies. This suggests that dispersion is not a significant problem in the interpretation of laboratory results in carbonate cores.

A large number of intermediate porosity samples demonstrated a larger velocity dependence on saturation than Gassmann predictions indicated. Gassmann also agrees more closely with the experimental results measured at higher pressures. We assume that this due to pore geometry effects, following work published by Toksoz et al (1976) and we have therefore used their model to interpret our results.

Toksoz et al

Toksoz et al (1976) developed a model which incorporates the effects of low-aspect-ratio pores and microcracks in velocity prediction. This model was developed because other theoretical techniques could not account for various phenomena observed in laboratory data, including the large velocity contrasts induced by saturation changes in very low porosity rocks, and the rapid change in velocity with increasing pressure observed in dry cores.

We studied the theoretical effects of low-aspect-ratio pores on velocity by selecting the Bedford Limestone sample from the Toksoz paper and then modifying the pore geometry to study quantitatively the theoretical velocity response. The water and gas saturated velocities in the Bedford Limestone sample were initially measured versus confining pressure by Nur and Simmons (1969). Toksoz and his colleagues later generated a pore aspect ratio spectrum for this sample that allowed their modeling technique to reproduce the laboratory measured results for both the compressional and shear velocities over ranges of both pressure and saturation. We used the Toksoz model to compute an oil-saturation curve, is slightly slower than, but which follows parallel to, the water saturated measurements made by Nur.

Next, we calculated Gassmann oil saturated velocity for the sample as a function of effective pressure. Figure 10 shows that the experimental data, and the Toksoz predictions demonstrate a rapid increase of compressional velocity with pressure for the dry sample, and comparatively little pressure dependency in the oil- or water-saturated conditions. By contrast, the Gassmann-predicted oil-saturated velocities follow parallel to the dry response. We believe that Gassmann's technique is unable to reproduce the laboratory data because it lacks pore geometry information. At higher pressures, when most of the compliant pores are closed, Gassmann predictions of saturated velocity are much closer to the velocities of the laboratory data, and this would tend to support our conjecture.

We further tested our theory by modifying the pore aspect ratio spectrum of the Bedford limestone. Porosities from aspect ratios less than 0.01 were added to the 1.0 aspect ratio class, and then pores with aspect ratios smaller than 0.01 were removed from the model. When dry velocities are estimated using the 1.0 and 0.01 pore aspect ratios, they show very little sensitivity to increasing overburden pressure (Figure 11). Oil saturation causes only a small increase in velocity (< 2%), with equal change occurring at all pressures. Gassmann predictions of oil-saturated velocity also parallel the dry results, but now actually predict a higher saturated velocity than was estimated using Toksoz.

INTERPRETATION and ROCK TYPE CLASSIFICATION

This theoretical study was used in the interpretation of our experimental results. Dry velocities have a low dependence on effective pressure in about 36% of our selected samples (27% of the dolomites, and 43% of the limestones), and in these same cores the saturation-induced velocity change is small (less than 5%). Gassmann predictions of the saturated velocities actually overestimate the experimentally derived data. We classify these cores as Type 3, having a low content of low-aspect-ratio pores.

A further 20% of our samples (40% of the dolomites and 7% of the limestones), designated Type 1, exhibit a strong pressure dependence, and a significant (greater than 10%) sensitivity to saturation changes. Oil- or water-saturated velocities in these rocks are larger than the Gassmann estimates. We characterize these cores as being significantly affected by micro-crack porosity. The remaining samples (33% of the dolomites and 50% of the limestones), designated Type 2, are intermediate in their pore geometry, having characteristics of both systems. Velocities vary from 5% to 10% with saturation changes and Gassmann predictions of the saturated velocities are consistent with the laboratory measurements.

Thin section analysis provides qualitative support for these observations, but we have been unable to determine quantitatively pore-aspect-ratio spectra that can be used in Toksoz predictions. This may be due to assumptions in the model relating to non-interaction of pores being violated in the measured spectra.

APPLICATIONS

The laboratory experiments provide some insight into acoustic velocity behavior in carbonate rocks but, in order to be of practical value, we must be able to use this knowledge in field applications. Information gained in the laboratory should be targeted at improving porosity estimation and pore-fluid identification in carbonate reservoirs.

Porosity Estimation from Acoustic Logs

Log analysts have typically used modified time-average relationships to estimate porosity from acoustic wireline logs in carbonate formations. Empirical corrections have been devised which have the effect of overestimating the pore-fluid transit time, and this has moved the average prediction closer to actual porosity. Our results indicate that porosities obtained from compressional wave acoustic tools will still be unreliable, due to the relatively poor correlation between P wave velocity and porosity in the laboratory data. This correlation is especially poor in gas-saturated formations. Predictions should be most accurate in oil- or brine-saturated reservoirs, or at depths of 3 km or greater, when effects of the micro-cracks are mostly removed.

Velocities generally correlate better with porosity in limestones than in dolomites (Figure 12). Velocity-porosity correlation in Type 3 rocks are numerically better than -0.9 regardless of wave type or saturation (Figure 13). Acoustic methods will provide excellent porosity estimates in this type of formation, even in gas-saturated conditions (Figure 14). Several of the Type 3 rocks had significant secondary porosity, in the form of vugs, and these samples did not degrade the correlations. This suggests that the practice of defining the difference between density and sonic determined porosity as "secondary" may not always apply.

Type 1 rocks exhibit poor correlations between porosity and velocity. Acoustic methods should be used with caution in determining porosity in formations of this type. We recommend crossplotting porosity and velocity for specific Type 1 facies within the reservoir to determine if a local relationship can be established.

Porosity Estimation from Seismic Data

All of the caveats in porosity estimation from logs also apply to seismic assisted mapping. Porosity-velocity functions should be independently derived in specific reservoir areas based on the best estimate of aspect ratio. Since pore geometry is depositionally and diagenically controlled, it may be possible to map zones of known characteristics through the reservoir and to use independent relationships within each zone.

Pore Fluid Identification

Discrimination of gas from oil or water should be possible in the majority of (all except Type 3) carbonate reservoirs (Figures 6 and 7). Theoretical and experimental results suggest that there is little contrast between oil and water saturated velocities, and it appears unlikely that these saturants will be separable with seismic techniques (Figures 15 and 16).

The ratio between compressional and shear wave velocities (Vp/Vs) is sensitive to gas saturation (Figure 17). Average Vp/Vs ratio is 1.85 in the gas saturated cores and 1.97 after oil saturation. Vp/Vs ratio is more saturation sensitive, on average, in dolomites than it is in limestones. This is probably due to a larger percentage of dolomites being rock Type 1 and more of the limestones being Type 3. This Vp/Vs ratio sensitivity suggests that amplitude versus offset (AVO) and shear wave seismic techniques should be applicable in identifying gas-saturated carbonate reservoirs.

Monitoring Movement of Reservoir Fluids

When recovery processes affect the acoustic properties of the reservoir rocks, it is possible to determine the movement of fluids using time-lapse seismic methods. This monitoring is accomplished by acquiring surveys before and after the production process and mapping differences between the surveys to determine the areas of the reservoir affected by the flood. Theoretical studies and experimental results indicate that seismic monitoring should be applicable in most carbonate reservoirs if gas or solvent replaces oil, and when water replaces gas (Figures 18 and 19).

CONCLUSIONS

We have recently completed an extensive study of acoustic velocity behavior in carbonate rocks. We have compared P and S wave velocity response to changes in pressure, porosity and saturation in limestone and dolomite cores. Shear wave velocities are relatively insensitive to changes in pore-fluid saturation, in accordance with theory. In contrast to the results published by Rafavich et al(1984), we found pore fluid saturant to have a significant effect on P-wave velocity in about 65% of the cores that we have measured. We have categorized carbonate rocks on the basis of their compressional velocity sensitivity to pore fluid change. This velocity sensitivity was determined at 20.7 MPa with a saturation change from gas to carnation oil. Velocity variations are 10% or greater in Type 1 rocks, 5% to 10% in Type 2, and 5% or less for Type3. Gassmann predictions of saturated velocities are too high for Type 3 rocks, compare favourably with Type 2, and are too low for Type 1. We have related these differences in velocity sensitivity to pore geometry effects with Type 1 rocks being highly influenced by low-aspect-ratio pores, and Type 3 rocks having more spherical pore systems.

Dolomites tend to have a broader range of pore geometry types with 40% Type1, 33% Type2 and 27% in Type3. Only 7% of the limestone samples are Type1, while 43% are Type3.

Water or oil should be distinguishable from gas saturation in all Type 1 or Type 2 carbonate rocks, at least to depths of 2 km, and often deeper. Seismic techniques, such as AVO analysis, which exploit shear wave information, should assist in determining pore fluids. Pore pressure changes should also be detectable in carbonate reservoirs, with Type 1 and 2 pore systems, particularly when depths are shallow.

We have found that porosity estimation from acoustic methods is subject to large uncertainties, unless the pore geometry of the formation is understood. Porosity estimation will be best in Type 3, and worst in Type 1 rocks. Porosity estimates are generally better when the rock is oil or water saturated, and at greater depths.

REFERENCE LIST

Journal article

Domenico, S.N., 1984, Rock lithology and porosity determination from shear and compressional wave velocity: Geophysics 49 p 1188-1195.

Doyen, P.M., 1988, Porosity from seismic data -- a geostatistical approach: Geophysics, 53, p 1263-1275.

Gassmann, F., 1951, Elastic waves through a packing of spheres: Geophysics 16 673-685.

Hicks, W.G., and Berry, J.E., 1956, Application of continuous velocity logs to determination of fluid saturationin reservoir rocks: Geophysics 21 p 739-754.

King, M.S., 1966, Wave velocities as a function of changes in overburden pressure and pore fluid saturants: Geophysics, 31, p 50-73.

Nur, A, and Simmons, G. 1969, The effect of saturation on velocity in low porosity rocks: Earth Plan. Sci. Lett.,7, p 183-193.

Rafavich, F., Kendall, C.H.St.C, Todd, T.P.,1984, The relationship between acoustic properties and the petrographic character of carbonate rocks: Geophysics 49 p 1622-1636.

Toksoz, M.N., Cheng, C.H., and Timur, A., 1976, Velocities of seismic waves in porous rocks: Geophysics 41p 621-645.

Walsh J.B., 1965, The effect of cracks on the compressibility of rocks: J. Geophys. Res. 70 p 381-389

Wyllie,M.R.J, Gregory, A.R., and Gardner, L.W., 1956, Elastic wave velocities in heterogeneous and porous media: Geophysics 21 p 41-70.

Wyllie, M.R.J., Gregory, A.R. and Gardner, G.H.F., 1958, An experimental investigation of factors affecting elastic wave velocities in porous media: Geophysics 23 p 459-493.

Proceedings

Doyen, P.M.,deBuyl, M.H., and Guidish, T.M.,1988, Geostatistical reservoir description from seismic impedance data:Presented at Joint SEG/EAEG Research Workshop on Reservoir Geophysics, Dallas.

Ensley, R.A., 1983 Direct hydrocarbon detection with P and SH wave seismic data: SEG 53 Ann. Intl. mtg. exp. abs.,p 349-351.

Paul, R.J., 1990, Seismic detection of overpressure and fracturing; an example from the Qaidam basin, Peoples Republic of China: SEG 60 Ann. Intl. exp. abs., p 176-79.

Fluid	Denisty (g/cc)	Velocity (m/s)	Viscosity (mPa.s)
Carnation	0.835	1410	17.0
Pentane	0.626	1030	0.24
Solvent	0.42*	----	----
Water	0.997	1492	1.0

* at 20°C and 17.3 MPa

Table 1. Physical properties of the pore fluids at 20°C and 1 atmosphere.

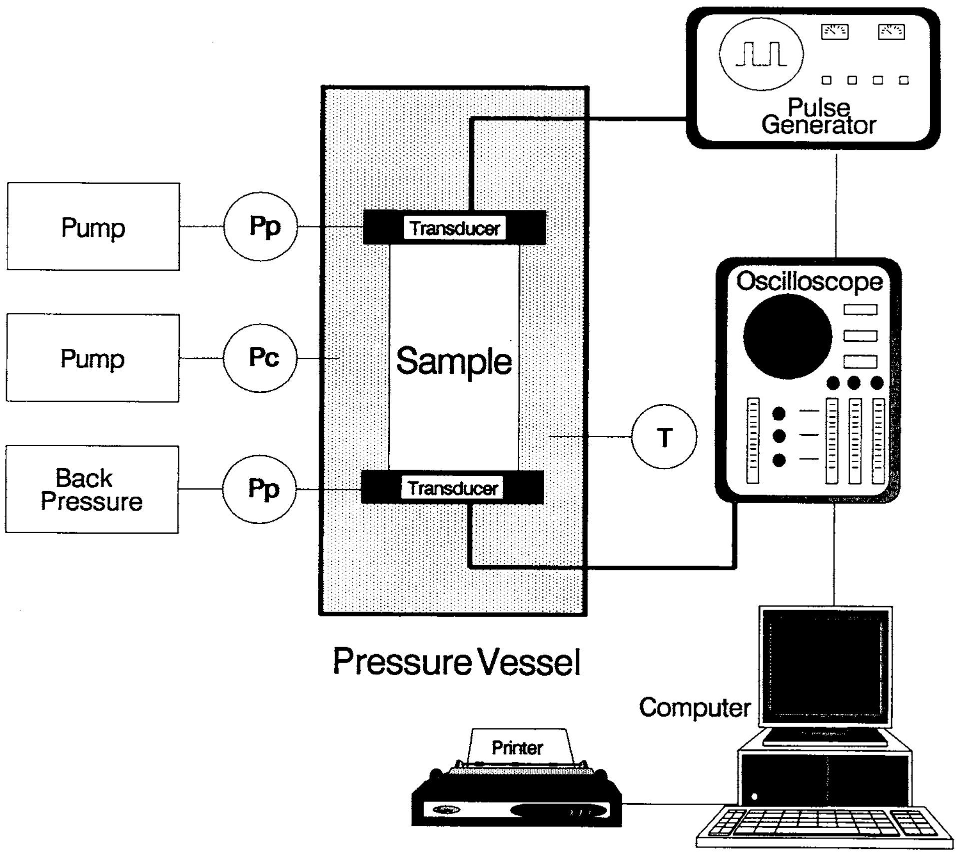


Figure 1. Schematic diagram of the acoustic measurement system.

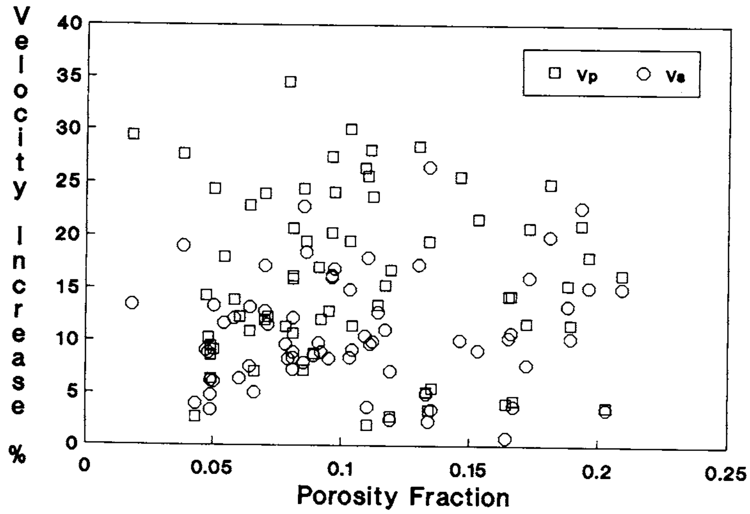


Figure 2. Vp and Vs increases in velocity in dry rocks as effective pressure increases from 6.9 MPa to 34.5 MPa.

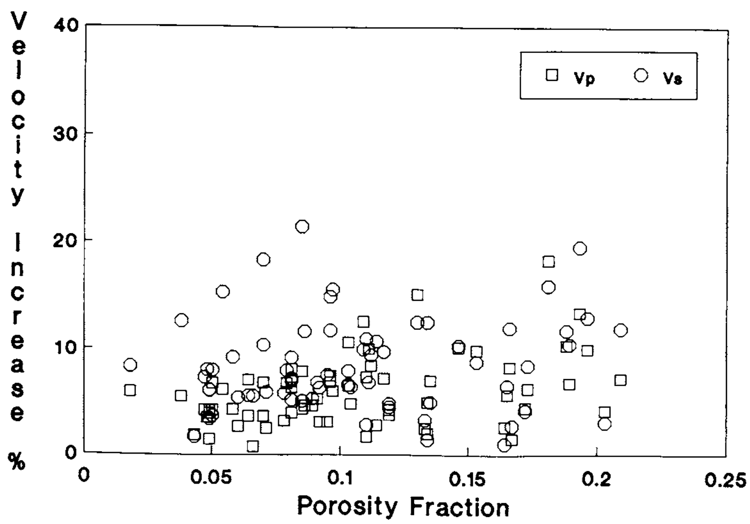


Figure 3. Vp and Vs increases in velocity in oil-saturated rocks as effective pressure increases from 6.9 MPa to 34.5 MPa.

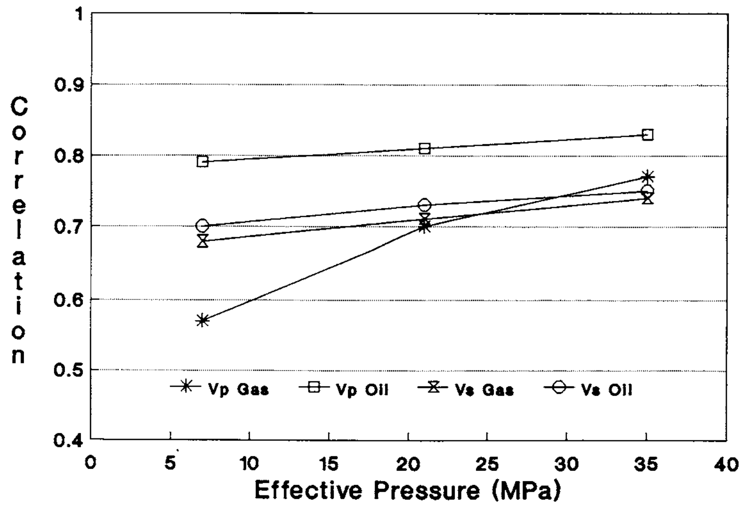
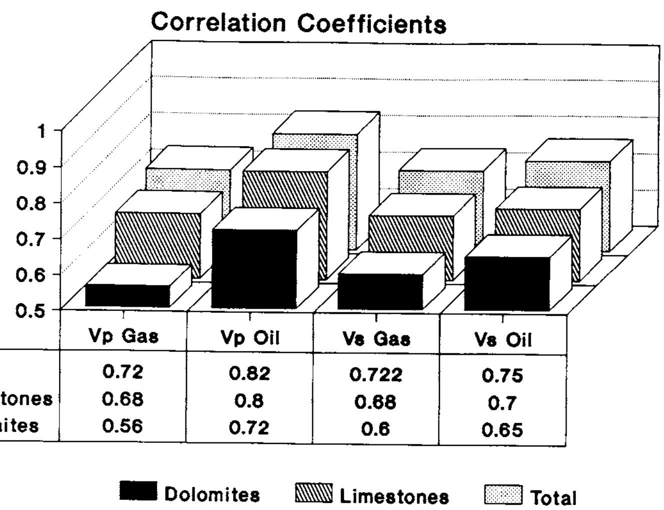


Figure 4. Velocity–porosity correlation coefficients as a function of saturation, wave type and pressure. Note: All coefficients are negative sign.



	Vp Gas	Vp Oil	Vs Gas	Vs Oil
Total	0.72	0.82	0.722	0.75
Limestones	0.68	0.8	0.68	0.7
Dolomites	0.56	0.72	0.6	0.65

Figure 5. Velocity–porosity correlation coefficients at 20.7 MPa. Correlations are pooled into limestone, dolomite, and total carbonates. Note: All coefficients are negative sign.

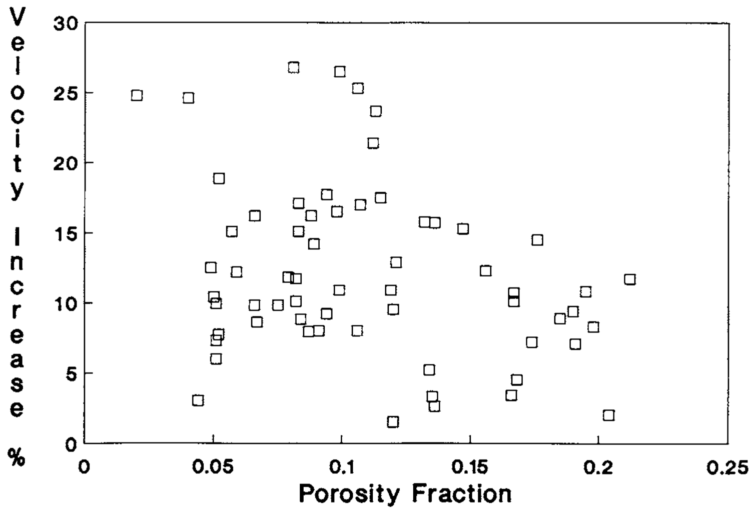


Figure 6. Vp Changes induced by saturating gas-filled samples with carnation oil at effective pressure of 6.9 MPa.

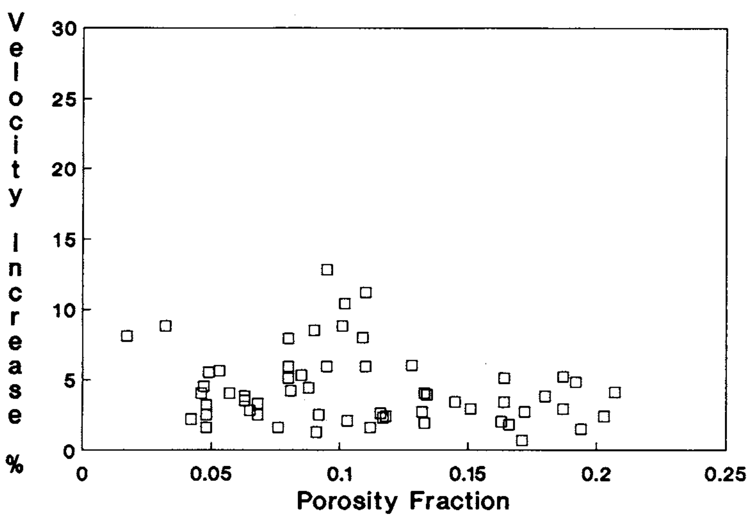


Figure 7. Vp changes induced by saturating gas-filled samples with carnation oil at 34.5 MPa.

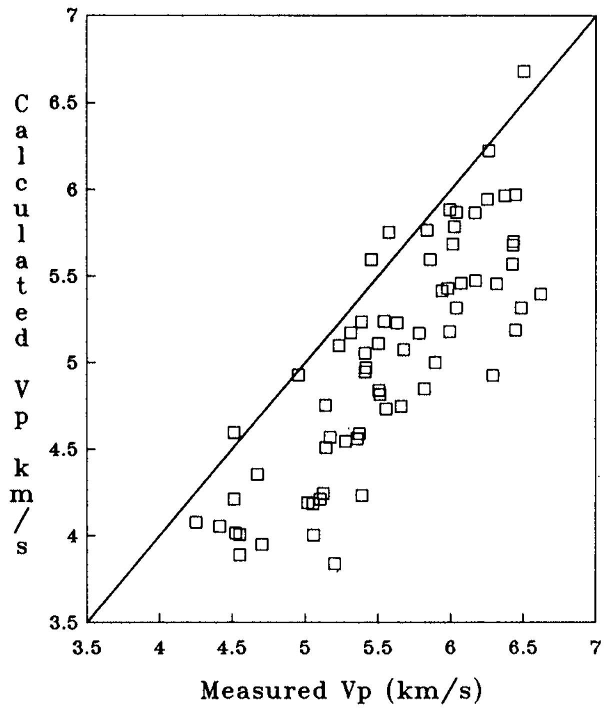


Figure 8. Time-average prediction of oil-saturated velocities at 20.7 MPa compared to measured values.

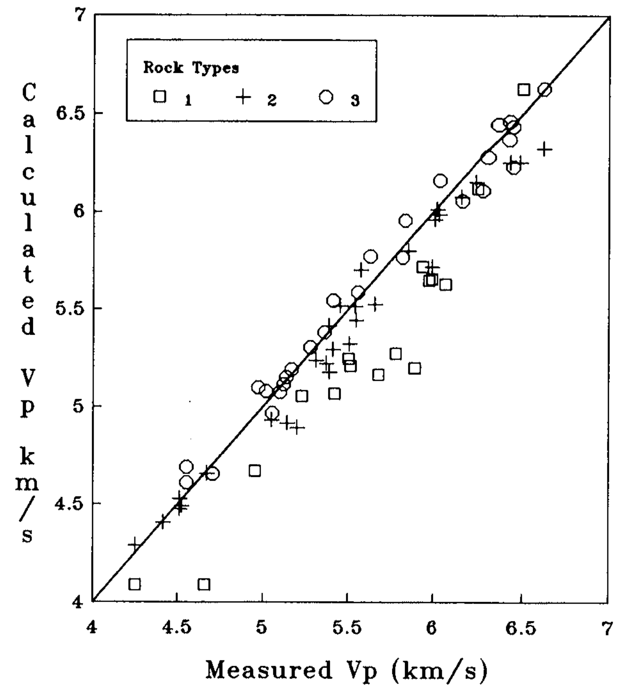


Figure 9. Gassmann predicted oil-saturated velocites compared to measured values at 20.7 MPa. Rock types are segragated on the basis of velocity response and pore geometry.

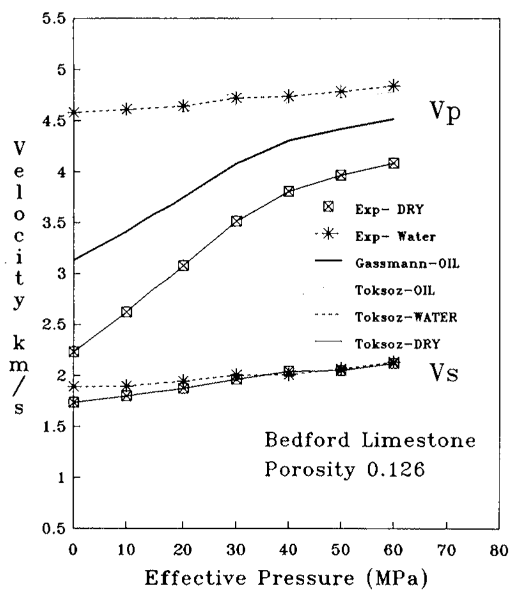


Figure 10. Comparison of experimental and theoretical (using Gassmann and Toksoz equations) velocities from the Bedford Limestone. Gassmann computed oil-saturated velocities does not reproduce the laboratory or Toksoz predicted results. Aspect ratio spectrum for velocity computation was derived by Toksoz et al (1976). Data acquired by Nur and Simmons (1969).

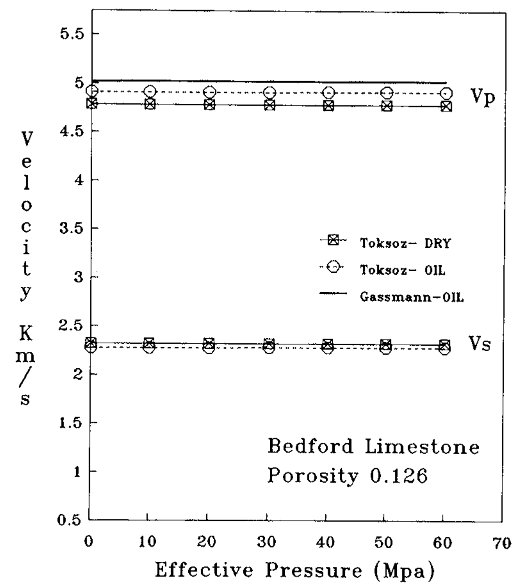


Figure 11. Theoretical velocities computed using Toksoz and Gassmann equations for Bedford Limestone with modified pore geometry. All pores with aspect ratios less than .01 are removed after the affected porosity was incorperated into the 1.0 aspect ratio pores.

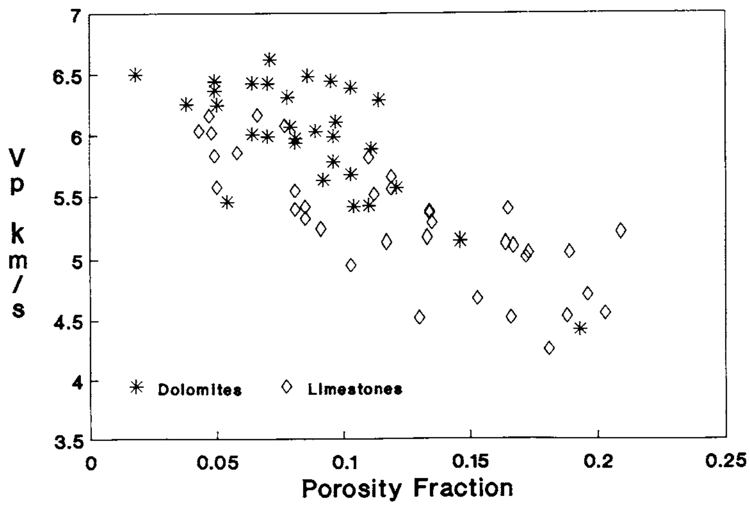


Figure 12. Cross-plot of porosity and compressional velocity in oil-saturated cores at 20.7 MPa effective pressure.

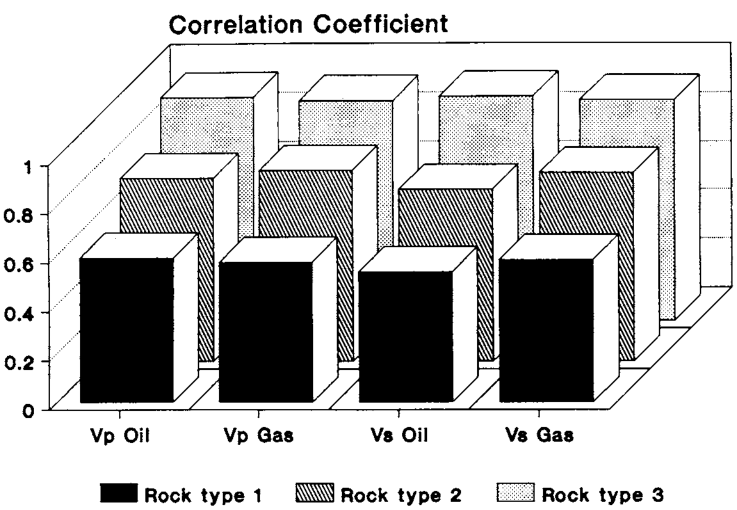


Figure 13. Correlation coefficients between porosity and velocity at 20.7 MPa effective pressure. Poor correlations exist in Type 1 rocks (high influence of low aspect ratio pores), while Type 3 (rounded pore system) rocks correlate well with porosity. Note: All correlations are negative sign.

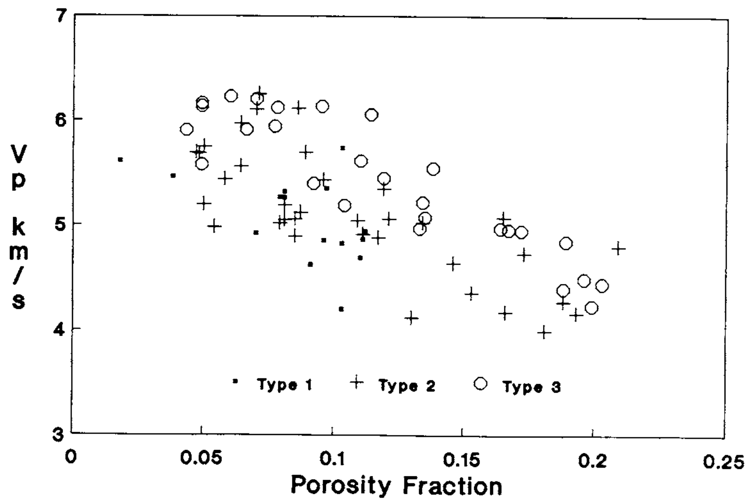


Figure 14. Cross-plot of porosity and compressional velocity in gas-saturated cores at 20.7 MPa effective pressure. Correlations are best in Type 3 rocks.

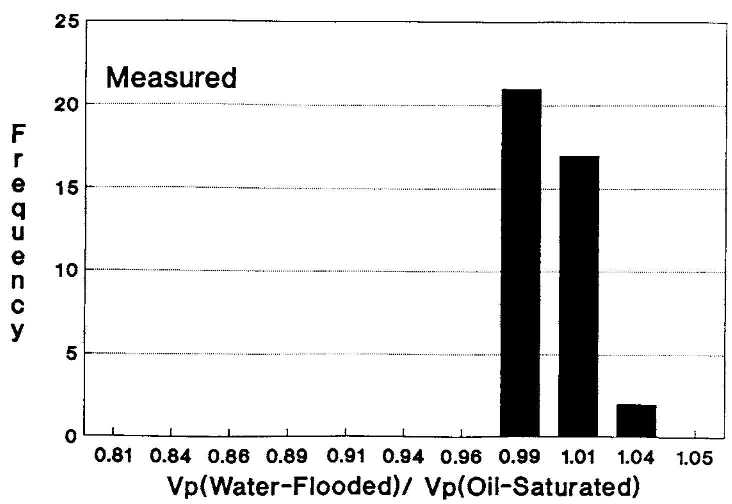


Figure 15. Effect of water-flooding oil-saturated rocks on Vp. Measurements made at 20.7 MPa effective pressure.

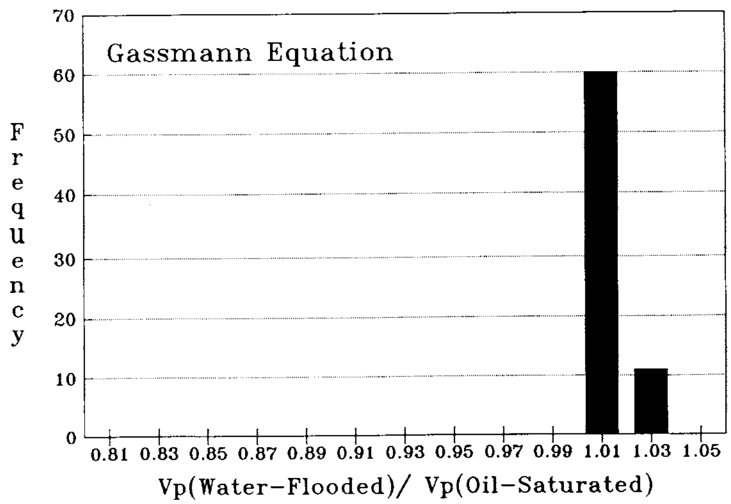
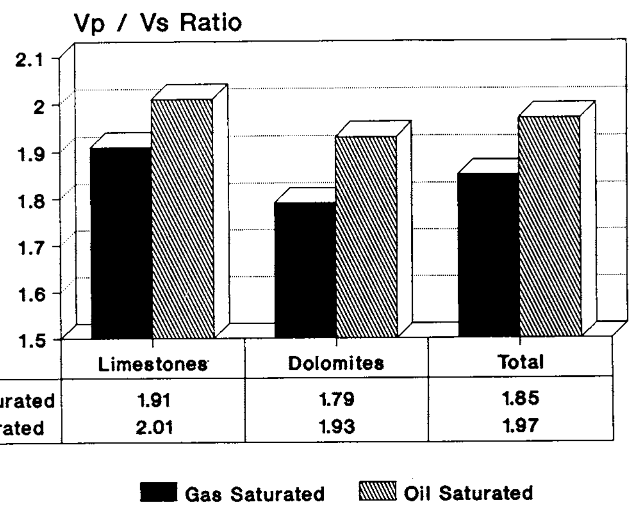


Figure 16. Calculated effect (using Gassmann equation) of water-flooding oil-saturated rocks on Vp.



	Limestones	Dolomites	Total
Gas Saturated	1.91	1.79	1.85
Oil Saturated	2.01	1.93	1.97

Figure 17. Vp/Vs ratio for oil- and gas-saturated limestone, dolomite and total carbonate rocks.

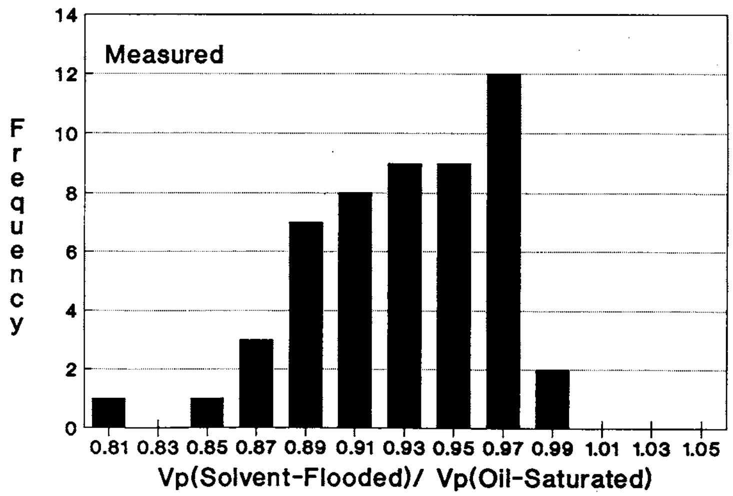


Figure 18. Effect of solvent-flooding on Vp in oil-saturated carbonate cores at 20.7 MPa effective pressure.

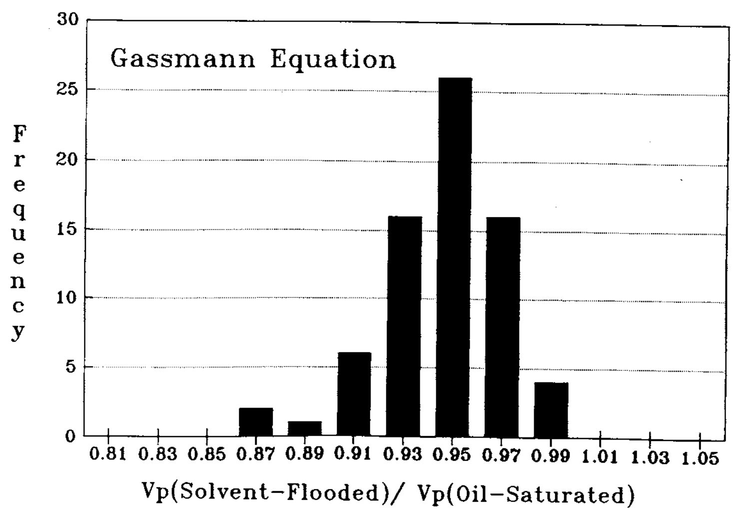


Figure 19. Calculated effect of solvent-flooding on Vp in oil-saturated carbonate cores at 20.7 MPa effective pressure.