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AMPLITUDE FEATURES OF FAST COMPRESSIONAL WAVES IN POROUS MEDIA FOR ZERO-OFFSET SYNTHETIC SEISMOGRAMS

By

ADEL A. A. OTHMAN
Department of Geology, Faculty of Science, University of Qatar
Doha, Qatar

مظاهر سعات الموجات التضاغطية السريعة في الأوساط المسامية على السيسموجرامات التخليقية صفرية الازاحة

عادل علي علي عثمان

تتأثر سعة الموجات السيزمية بنوع الوسط الذي تمر خلاله لذلك صمم نموذج جيولوجي لدراسة التغير في سعات الموجات السيزمية داخل عدة صخور لها درجات مسامية مختلفة . لقد أختير أربع أنواع من الصخور لتوضيح مظاهر إختلاف السعات وذلك باستخدام السيسموجرامات التخليقية .

Key Words: Amplitudes, porosity, synthetic seismogram

ABSTRACT

The seismic amplitude are clearly affected by the type of medium through which waves are propagated. A geologic model was designed to study the changes in amplitudes of the seismic waves within several rocks of different porosities. Four rocks are selected to show these features using synthetic seismograms.

INTRODUCTION

Geophysicists, in the sixties, became interested in using the amplitude of the reflected events as a direct method for showing the presence of hydrocarbons (Domenico, 1974). Until 1970, the variations in the amplitude of the reflected signal were used only as a qualitative tool for identifying seismic events, some quite valuable information. A quantitative analysis of the character of reflected signal might lead to more information of some of the seismic properties of the rock formations (Sheriff, 1974). After 1972, the true amplitude techniques were used supported by the introduction of computer facilities.

The velocity of seismic waves that travel through porous media depends not only on the matrix velocity, but also on the porosity and the characteristics of the interstitial fluids. Amplitudes of reflected seismic waves are an important evidence of the anomalous effect of interstitial fluids (water and/or hydrocarbons). This depends on the reflection coefficients of the interfaces, separating different lithologies in a sequence. The polarity of the reflected seismic pulse can help to identify a saturated reservoir interface (Sherriff, 1974). Phase reversals occur if the reflectivity changes sign at the boundaries of the reservoir.

Bright spots became the hottest topic in exploration. Observations of time sections led to false synclinal structures corresponding to reflections from below the gas horizons (Hammond, 1975). Some characteristics of the time signal are expected to show certain typical changes over the region containing gas, oil or other fluids.

Quantitative estimate are presented here to discuss some of the above mentioned parameters, taking into consideration that the computations are carried out for the zero-offset case.

THE GEOLOGICAL MODEL

The geological model that has been chosen for investigations is shown in (Fig. 1). It consists of three layers (A, B and C). Layers A and C are non-porous shale. Layer B is selected to be either dolomite, limestone, or sandstone. In a porous medium, Biot's theory predicts three kinds of body waves, two compressional and one shear (Biot, 1956 a, b). One of the compressional waves, which is called the first kind, are faster than the second kind. The second kind of compressional wave is highly-attenuated being related to a diffusion process (Stoll, 1974). The seismic parameters of the model (slow P-wave and S-wave are neglected) are given in (Table 1). S_{ac} are the reflected signals from the interface between the layer A and B. S_{bc} are the signals which firstly reflected from the interface between the layer B and layer C and then transmitted through the interface between layers B and A. Horizontal display for the reflected and transmitted seismic rays in (Fig. 1) represents time (Kanasewich, 1975) to show a zero offset case.

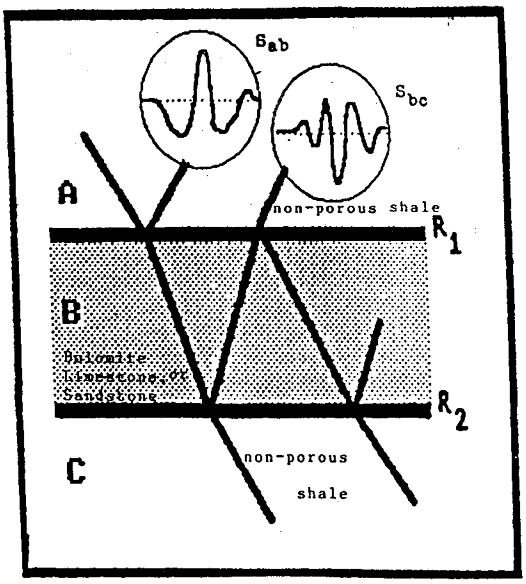

Fig. (1): A three layer model A,B, and C with reflection coefficients R_1 and R_2. S_{ab} denotes the reflected signals from the interface between A and B. S_{bc} denotes reflected signals from the interface between B and C and then transmitted through the upper interface of layer B.

THEORY

Exploration geophysicists are interested in the lithology, porosity, permeability, saturation, and type of pore fluid of the subsurface formations. Therefore, there are many authors, who tried to relate the propagated wave velocity to rock parameters. The time average equation empirically (Wyllie *et al*, 1962) relates velocity and formation parameters for a wide range of porosity:

$$V = \{ (\phi / V_f) + (1 - \phi) / V_m\}^{-1} \qquad (1)$$

where ϕ is the porosity, V is the liquid saturated rock velocity, V_f is the pore fluid velocity, V_f is the matrix velocity (massive rock).

Table 1
Numerical parameters used in the studied model

	Matrix Velocity (m/sec)	Matrix density (gm/cc)	porosity (%)
Layer A:			
Shael	4500	2.60	0
Layer B:			
Dolomite	7000	2.87	5 to 15
Limestone	6400	2.69	10 to 20
Sandstone	5500	2.65	15 to 35
Shale	4500	2.60	40 to 50
Layer C:			
Shale	4500	2.60	40 to 50
Fluids:			
Water	1500	1.00	-
Oil	1200	0.85	-
Gas	480	0.15	-

The time average equation (1) displays a relationship between velocity and porosity which, according to Gardner and Harris, 1968, can be used for shallow porous layers. This equation cannot be applied for gas-saturated materials. Therefore, a modification for the equation is needed. In case of gas-saturated reservoirs, the modified Wyllie equation (Wyllie *et al.*, 1962), would take the following new form (Marschall, 1984):

$$V = \{ (\phi\, S_w/V_w) + \phi\, (1- S_w) / V_g \log (Cg/C_m)) + (1- \phi) / V_m\}^{-1} \qquad (2)$$

where V is the wave velocity in a gas and fluid saturated porous medium, V_w is the wave velocity in water, V_m is the wave velocity in matrix, V_g is velocity in gas, S_w is the water saturation fraction, C_g is the gas compressibility, C_m is the matrix compressibility. The compressibility ratio of the fluids (gas) with respect to solids is nearly equal to 10 (Marschall, 1984), and in equation (2) the logarithm of this ratio will be equal to one.

Synthetic seismograms S(t) can be computed from the convolution of the source wavelet W(t) with reflectivity R(t). It may be expressed as:

$$S(t) = R(t) * W(t) \qquad (3)$$

The asterisk denotes convolution. The reflection coefficient R is computed by the equation (4):

$$R = (d_{i+1}\, V_{i+1} - d_i\, V_i) / (d_{i+1}\, V_{i+1} + d_i\, V_i) \qquad (4)$$

i denotes the i-th layer and

$$d = \phi\, d_f + (1 - \phi)\, d_m \qquad (5)$$

where d is the effective density, d_f is the fluid density, d_m is the matrix density.

Using the modified equation (2), a great number of synthetic traces may be computed, for each of which the suitable reservoir parameters are modified. This set of traces may be used as a guideline for subsequent interpretation of the actual seismic data, after having applied the appropriate frequency-band limitation in form of the input source wavelet.

DESCRIPTION OF MODEL OUTPUT

A simple calculation using the modified equation (2) was carried out to relate the velocity with the porosity over the given ranges in the studied geologic model (see Table 1). Figure 2 shows the plots of all the four rocks: shale, sandstone, limestone, and dolomite at gas-, oil- or water- saturated cases. The wave velocity in dolomite decreases with increasing porosity and is lower in the gas- saturated case than in the water-saturated one. This relation is (for the indicated range) almost linear in limestone, and the velocity of the gaseous case is still lower than that of oil and of water saturated cases. A weak sensitivity appears in saturated sandstones. In shale, the velocity is almost insensitive to porosity (in the studied model).

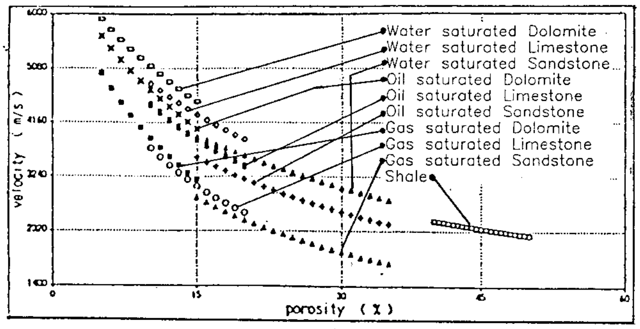

Fig. (2): Seismic velocity as a function of porosity for limestone, dolomite, sandstone, and shale, in the studied model, in (G) gas- , (O) oil-, and (W) water-saturated medium.

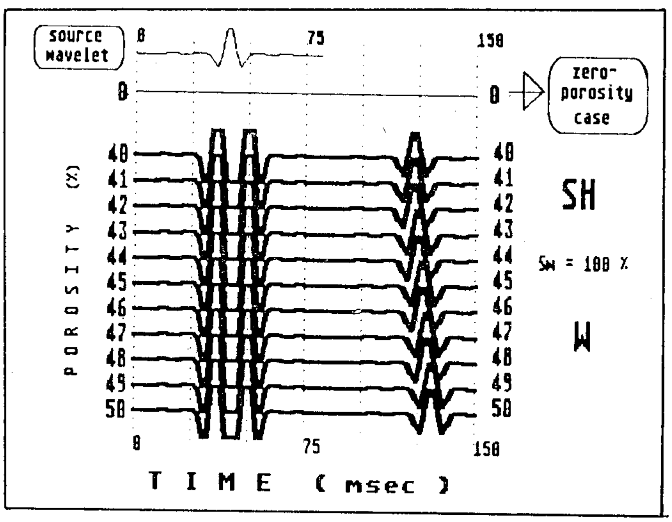

Fig. (3): Calculated synthetic seismograms in case layer B is a water-saturated shale, for different porosity values and for water saturation = 100%. Note that the first arrivals are from the upper boundary of layer B and the second ones from the lower boundary. The magnification of the second reflection led to complicate the shape of the first reflection.

The author has written a computer program to execute the synthetic seismograms by inserting the porosity and following its effects on amplitudes. In general, to calculate a synthetic seismogram the reflection coefficients and the source wavelet must be known. These reflection coefficients for the zero offset case depend mainly on the wave velocity and also on the density of the medium. The wave velocity (V) is affected by the porosity values as shown in equation (2), and the density value of the medium is highly affected by porosity as in equation (5). The source wavelet is a zero phase one and its central frequency equals 50 Hz. Computations of the displayed synthetic seismograms in the present work depend mainly on the reflectivity method. A test was made in Figure (3) to show the presence of porosity effects, if layer B was a shale flanked by the shale on the top as well as at the bottom. Reflection coefficients are zero in the case of massive shale in layer B; i.e. if the porosity is zero. According to the introduction of the porosity into layer B, a difference in velocity occurred. A series of plots were computed for dolomite, limestone, and sandstone in both gas-and oil-saturated cases. Every plot consists of three parts; each one contains many synthetic traces calculated over a given range of porosity for every rock type. In each part, a synthetic trace was calculated for a massive (non-porous) rock to consider it in the comparative studies when porosity is introduced into the calculations.

SYNTHETIC SEISMOGRAMS IN GAS AND OIL SATURATED CASES

1. Dolomite

In a gas saturated dolomite, as in all following diagrams, the second reflected event always is from the bottom of layer B (dolomite), with a delay time compared to the massive case, which increases with increasing porosity. These time shifts are larger at higher porosities. Figure (4A) shows also a reverse of amplitude polarity starting at a porosity equal to 8%. In the mixed case (gas / water), this polarity reversal takes place at a porosity value of 10%, as shown in Figure (4B). Polarity reversals appear at a porosity of 15% in a water-saturated dolomite, as shown in Figure (4C). Time shifts of the second event (the reflection from the bottom of layer B) are generally decreased by increasing the water saturation percentage in rock.

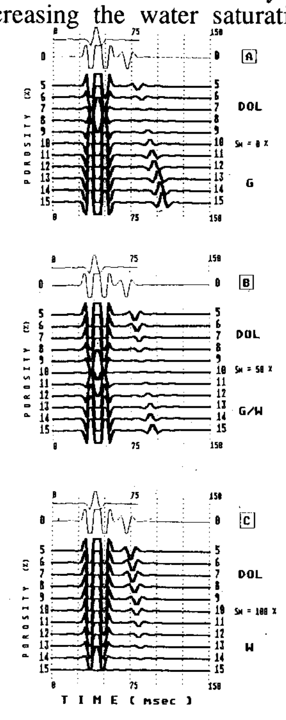

Fig. (4): Synthetic seismograms for partially gas-saturated dolomite, calculated for layer B in the studied model at different water-saturation values equal to 0% (A) and 50%(B) and 100% (C).

Figure (5A) shows a case of oil saturated Dolomite, in which the polarity reversals occur at a porosity equal to 12%. These reversals start at a porosity equal to 14% in the mixed (oil/water) case, see Figure (5B). Polarity reversals in water-saturated case are mentioned above and shown in Figure (5C). The delay is, in general, smaller than that in the gas-saturated dolomite.

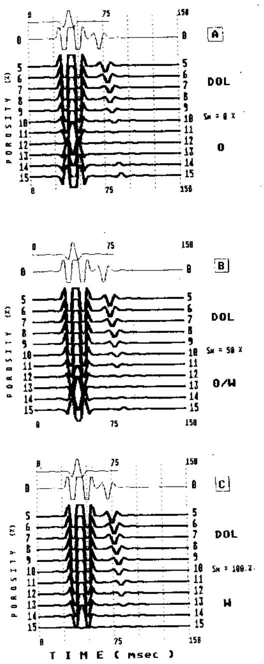

Fig. (5): Synthetic seismograms for partially oil-saturated dolomite, calculated for layer B in the studied model at different water-saturation values equal to 0% (A) and 50%(B) and 100% (C).

2. Limestone:

Polarity changes its sign with respect to a massive limestone, as seen in Figure (6). Gas-saturated rocks give a large transit times of the second event by increasing porosity fractions, see Figure (6A). These time shifts will be similar in a gas-water mixture as shown in Figure (6B), due to presence of water, (compared to gas-saturation). Water-saturated limestone displays a case of polarity reversals at lower values of the porosity, see Figure (6C).

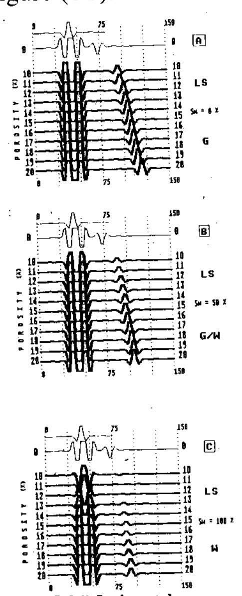

Fig. (6): Synthetic seismograms for partially gas-saturated limestone, calculated for layer B in the studied model at different water-saturation values equal to 0% (A) and 50%(B) and 100% (C).

At an oil-saturated limestone, time delays are the only difference with respect to the gas-saturated case. These delays are smaller than at gas saturation, as presented in Figure (7A). Introduction of water in the model decreases the time shift quickly, as shown in Figure (7B). This is clearly shown for a water-saturated limestone, as seen in Figure (7C). Reversal of polarity appears at a porosity of 12%.

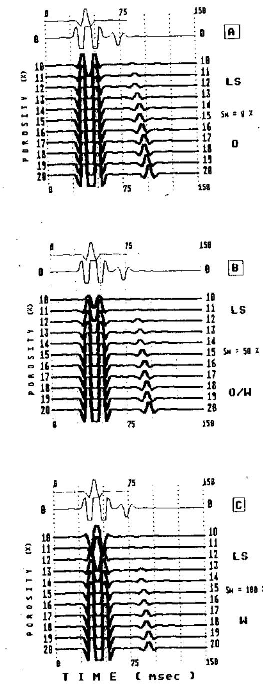

Fig. (7): Synthetic seismograms for partially oil-saturated limestone, calculated for layer B in the studied model at different water-saturation values equal to 0% (A) and 50%(B) and 100% (C).

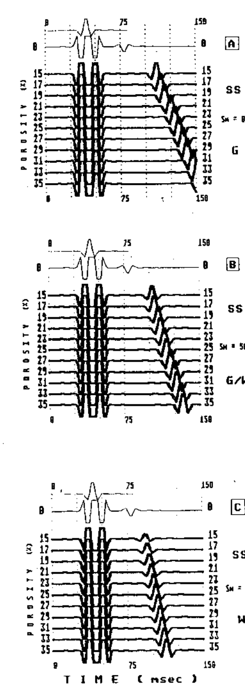

Fig. (8): Synthetic seismograms for partially gas-saturated sandstone, calculated for layer B in the studied model at different water-saturation values equal to 0% (A) and 50%(B) and 100% (C).

3. Sandstone:

A porous sandstone is highly affected by the presence of pore fluids. Some features are observed in Figure (8A), for the gas-saturated case. Time shifts increase at higher porosities but once the water is introduced, these time shifts decrease, as shown in Figure (8B) and Figure (8C).

For oil-saturated sandstones polarity reversals are present for all porosities as well as for gas-saturation. The observable difference is a decrease of time shifts in massive sandstones compared to gas-saturated ones, as displayed in Figure (9A0. By increasing the percentage of water saturation, the time shifts decrease as shown in Figure (9B) and Figure (9C).

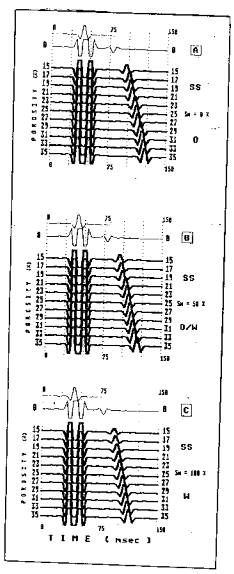

Fig. (9): Synthetic seismograms for partially oil-saturated sandstone, calculated for layer B in the studied model at different water-saturation values equal to 0% (A) and 50%(B) and 100% (C).

AMPLITUDE CHARACTERISTICS DUE TO LAYER B

The following discussion is restricted to the study of the shape of the events reflected from the bottom of layer B. Amplitudes in a porous Dolomites have different features over the selected porosity range, at different degrees of water saturation. Figure (10) shows the effects of three different cases of saturations on the amplitude. A quick comparison between the three cases confirms that in a gas-saturated dolomite the amplitudes are higher than the other cases in the graph (bright spots). The calculated amplitudes show an increase by increasing the porosity values. The presence of water in the formation decreases the amplitudes of seismic arrivals, and moves the upper curve downwards. Before and after intersecting the zero-marked kine (solid line), the amplitudes show changes from negative to positive values; i.e. polarity reversals. These reversals start at porosity higher than 6% (for S_W = 0%), and higher than 8.25% (for S_W = 50%).

In the oil-saturation case amplitudes are smaller than those of gas-saturated rock. Polarity of amplitudes changes signs at porosity higher than 11.75%. According to the presence of water, the last value will be shifted to a porosity higher than 13.25%. If layer B is a water-saturated dolomite, amplitudes of travelling events increase by increasing porosity. A reverse polarity appears at porosities higher than 12.5%. The amplitudes of water saturated case are generally larger than those of oil mixed with water. At a porosity of 8.25%, seismic waves with the same amplitude, in both oil- and water-saturated cases, as observed in Figure (10), for the studied hypothetical model.

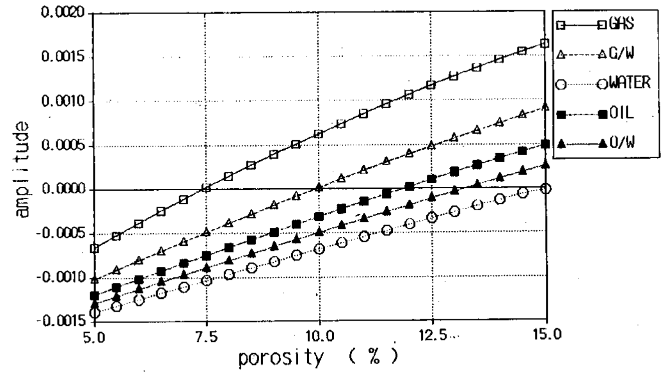

Fig. (10): Seismic amplitude and porosity for different S_W=0%, 50% and 100% in gas- and oil- filled porous dolomite, resulted from model calculations.

The situation is different in porous limestone as observed in (Fig. 11). Seismic waves that travel through a gas-saturated limestone have larger amplitudes which changes polarity upon reflection at the bottom of layer B. The only exception is for S_W = 100% for porosity values less than about 10.5%. Gas amplitude decreases downwards as well as water saturation increased up to 50%, as presented in (Fig. 11). A similar condition observed at oil-saturated rocks, where amplitudes decrease by increasing S_W.

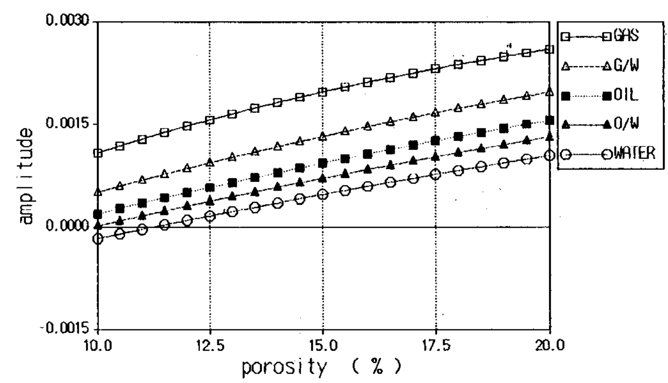

Fig. (11): Seismic amplitude and porosity for different S_W=0%, 50% and 100% in gas- and oil- filled porous limestone, resulted from model calculations.

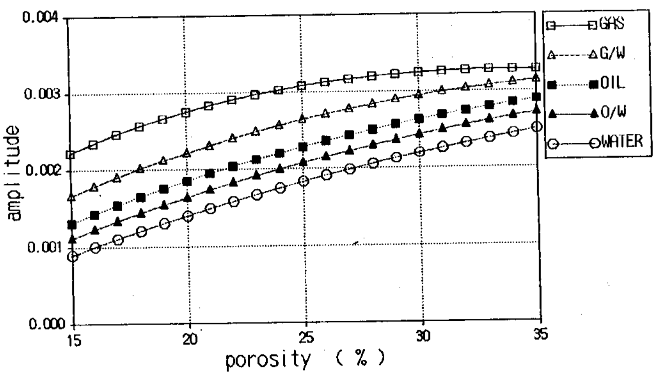

Fig. (12): Seismic amplitude and porosity for different S_W=0%, 50% and 100% in gas- and oil- filled porous sandstone.

Amplitudes of waves travelling through a gas-saturated sandstone have a non-linear relation with porosity, as shown in (Fig. 12). They increase steadily before porosity reaches 25%. If the water saturation increases, gas amplitudes decrease. Oil-saturated amplitude decrease by increasing the water content in the pores, as shown in (Fig. 12). Water-saturated sandstones show amplitudes of minimum values and of linear nature by increasing porosity. There are no polarity reversals detected as seen in (Fig. 12).

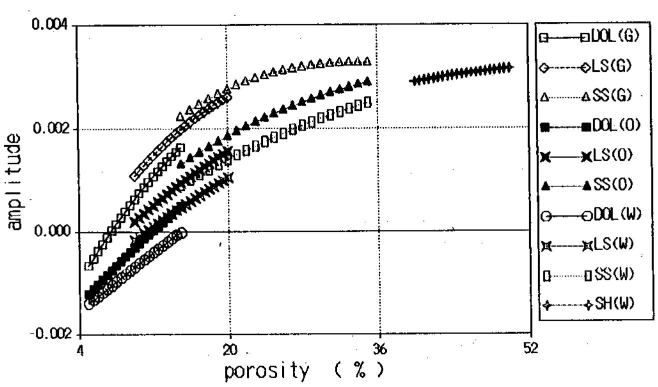

Fig. (13): Seismic amplitude and porosity for dolomite, shale, limestone and sandstone; at (G) gas-, (O) oil-, and (W) water-saturated cases of the second event in the studied model.

A complete picture was created in (Fig. 13). Amplitudes of the waves passing through all the four rocks are displayed together. Polarity reversals take places at porosities starting from 7.5% to 15%. Sandstones have higher gas-saturated amplitudes than other studies rocks in the present work. Shales have also large amplitudes at higher porosities.

FIELD DATA

Three field records are collected from different published work to explain the above mentioned discussed ideas (Payton, 1977). These examples include bright spot amplitudes, which help in the detection of gas reservoirs. (Fig. 14A) and (Fig. 14B) show the seismic signature of gas fields. Amplitudes are higher here than in the adjacent horizons, which describe clearly the bright sports, giving a similar amplitude characteristic as that calculated in the studied model. In (Fig. 14B), a drilled well is indicated on the seismic line. Well information is tied to the presented time section, and the black markers are sandstones. GAs-saturated sandstone, as mentioned in the previous section, gives higher amplitudes (bright sports).

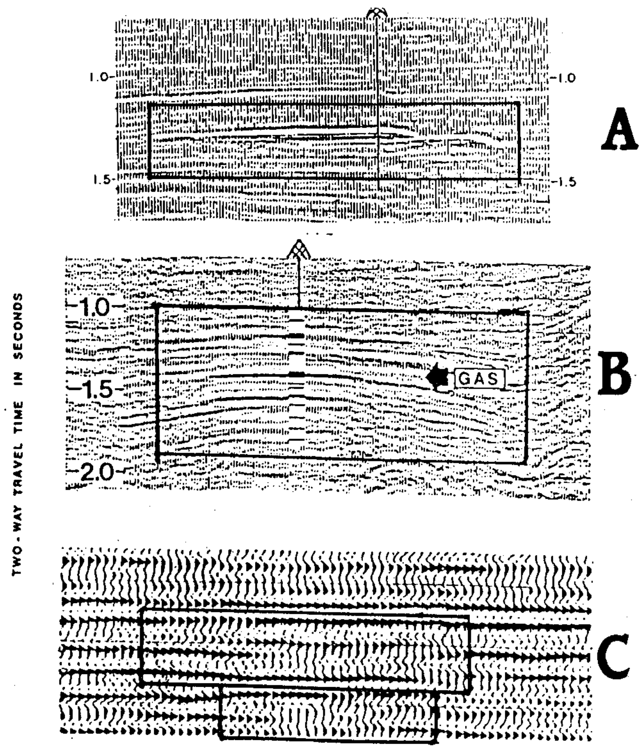

Fig. (14): Field time sections describe the bright spots and polarity reversals.

In (Fig. 14C), the two boxes display the polarity reversals which may be interpreted as structural changes (i.e., fault) or as a difference in the pore fluid content, as observed from the calculated results of this studied model.

CONCLUSION

The following conclusions can be considered: 1. amplitudes of seismic waves in porous media are highly affected by porosity, the type of fluid (gas, oil, water) and the amount of fluid (porosity, saturation). Addition of water in the decreases these amplitudes. 2. In dolomite and limestone polarity reversals appear if the varying porosities cross a specific value.

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