Numerical simulation of the seismic response of oil and gas reservoirs

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Abstract

The aim of this work is to study the seismic response of typical geologic models of oil and gas reservoirs. Seismic sections are generated by gathering numerically simulated zero-offset seismograms. Zero-phase Ricker wavelet is assumed to be the source signature in the convolutional process of seismogram generation. We investigate the resulting amplitude anomalies in seismograms associated to geological models containing structures commonly found in sandstones reservoirs, such as wedges (pinch outs) and sandstones lenses geometries. The present study can be applied in practice for understanding the inner geology of reservoir and for delimiting its boundaries.

Introduction

Reservoir characterization has fundamental importance for maximizing the production of hydrocarbons. For that purpose, several tools in different scales of investigation take part in the physical properties characterization methodologies. In respect to geophysics, the development, characterization and delineation of the reservoir rocks are done in the macro scale using, for instance, reflection seismics.

In order to understand the seismic amplitude responses of reservoirs, it is necessary to control a large set of information about rock physics and elastic properties of sedimentary rocks, as well as the fluids that are within porous space. Then, Gassmann fluid substitution, for instance, is used for the investigation of the correlation between elastic properties and rock physics. Several studies about these correlations can be found in published papers, for example Wang & Batzle (1992) and Wang (2001).

Here, we used seismic software to study these property relations in geologic model of reservoirs, by interpreting the resulting seismic responses in normal-incidence seismic sections. Repeated simulations using other geologic models provided insights of how the physical properties of rocks and fluids modify the seismic response. In addition, the present work can be used as a reference to predict the geology inside and at the boundaries of the reservoir under study.

Relation between seismic and rock physics properties

The analysis of numerically simulated seismic sections helps understanding the interaction between the types of rocks and fluids by the calculating seismic wave attributes, that is, traveltimes, reflection amplitudes and phase variation.

The seismic properties (i.e., seismic velocities) are affected by several factors, such as pressure, temperature, saturation, type of fluid and porosity. The variation of one of these factors implies in changes in respective seismic property. Table 1 shows the rocks and fluids properties and environmental factors that influence the seismic properties of sedimentary rocks.

Table1: Physical properties influence the seismic properties (with increasing importance from top to bottom) (Wang, 2001).

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

According to Wang (2001), due to the better contact and connectivity between grains of very consolidated or strongly cemented rocks, the magnitudes of seismic properties (compressional velocity – Vp, and shear velocity – Vs, and, consequently, acoustic impedance) are high.

The effect of clay content in the seismic properties depends on the clay particle position in the rock. Statistically, rocks with high clay content can present low velocities and high Vp/Vs ratio (see equation 1).

Texture characteristics also affect the seismic properties. Generally, sand with large size of grains and poorly selected have high velocities due to lower porosity derived from their great contact between the grains. Sand with angular grains possess lower seismic properties, but high Vp/Vs ratio. The opposite occurs with spherical sand.

When it comes to fluid properties, Wang (2001) reports that rocks with heavy and viscous oils tend to have high seismic properties. Saturated rocks with heavy oils show high compressional velocities, while shear velocity is less affected. Besides this, saturated rocks with gas have low compressional and shear velocities, and also low densities, resulting in low Vp/Vs ratio. The presence of gas affects the seismic properties when saturation is above 5%. The compressional velocity increases in fluid-filled rocks and decreases shear velocity, implying in an increase Vp/Vs. These relations are totally reversed when gas is the saturating fluid.

The mineralogical content in rocks affects directly the velocity through shear and bulk modulus of rock matrix. And, it also controls the cementation and the porous shape. Further, cement type influences the velocity of waves. For instance, carbonate and quartz cements have higher velocities than clay cements.

Poisson ratio (σ) is very useful in rock physics because it has a direct relation to Vp/Vs ratio. It is given as:

$$\frac{Vp}{Vs} = \sqrt{\frac{1-\sigma}{1/2-\sigma}} \Leftrightarrow \sigma = \frac{1}{2}\left[1 - \frac{1}{\left(Vp/Vs\right)^2 - 1}\right], \qquad (1)$$

The magnitude of the Poisson ratio depends on composition, anisotropy and porous pressure. It can vary between 0.05 for hard rocks, and 0.45 for soft rocks, depending on shear modulus' material. The pore pressure decreases Vp and Vs, but, in the presence of fluid, it occurs a major decrease in Vs than in Vp, leading to a high magnitude for the Poisson ratio.

Wang (2001) also claims that the saturated rocks with gas fluids have low compressional and shear velocities, besides low densities, resulting in low Vp/Vs. As a result, Vp/Vs ratio is a good direct hydrocarbon indicator in gas-saturated porous rocks.

Equation (1) reflects that the measurements of Vp and Vs is of great important in reservoir characterization, because it allows estimating the Poisson ratio. This parameter can help predicting lithology with more accuracy because of low error propagation.

Gassmann's theory

Fluid substitution is an important tool for seismic rock physics analysis, providing that it helps fluid-type identification. The objective of fluid substitution is to model the seismic properties and density at a given reservoir condition and pore fluid saturation, such as 100% of water saturation or hydrocarbon with oil or only gas saturation.

Gassmann's equations are the relations most widely used to calculate seismic velocity changes resulting from different fluid saturations in reservoirs. The parameters required can be directly measured or assumed, such as porosity, clay content, temperature, pressure, salinity and others. The calculations are more stable and the results are more realistic.

The parameters necessary to estimate the seismic velocities after fluid substitution are the elastic moduli (i.e., incompressibility and shear modulus), which can be computed using the Gassmann's equations. These equations relate the incompressibility of a rock to its pore, frame and fluid properties. The incompressibility is given by:

$$K_{sat} = K_{frame} + \frac{\left(1 - \frac{K_{frame}}{K_{matrix}}\right)^2}{\frac{\phi}{K_{fl}} + \frac{(1-\phi)}{K_{matrix}} - \frac{K_{frame}}{K^2_{matrix}}}, \qquad (2)$$

where, K_{sat}, K_{frame}, K_{matrix} and K_{fl} are the incompressibilities of the saturated rock, porous rock frame, mineral matrix and pore fluid, respectively, and ϕ is the fractional total porosity.

In the Gassmann formulation, the shear modulus is independent on the pore fluid and remains constant during the fluid substitution. The magnitude of the incompressibility of the rock frame and matrix can be obtained from laboratory using core samples, empirical relationship or wireline log data. Density of mineral matrix, ρ_{matrix}, can be estimated by arithmetic averaging of densities in individual minerals. The fluid incompressibility, K_{fl}, and density of the pore fluid, ρ_{fl}, are estimated by averaging the values of individual fluid type. For more details, see Han & Batzle (2004).

After calculations and considerations above, we can get the density of a saturated rock, which can be simply calculated as:

$$\rho_B = \phi\rho_{fl} + (1-\phi)\rho_{matrix}, \qquad (3)$$

where, ρ_B is the density of saturated rock, ρ_{fl} is the density of pore fluid chosen and ρ_{matrix} is the density of rock matrix. Finally, seismic velocities of an isotropic material can be estimated by using K_{sat} and ρ_B already calculated. P-wave and S-wave are estimated as:

$$Vp = \sqrt{\frac{K_{sat} + 4/3\,\mu}{\rho_B}}, \qquad (4)$$

and

$$Vs = \sqrt{\frac{\mu}{\rho_B}}, \qquad (5)$$

where, Vp and Vs are the P-wave and S-wave velocity in saturated rock.

Reflection Coefficients

The reflection coefficients of a plane wave are obtained by partition of seismic amplitudes derived from the incidence of this wave on a plane interface, which separates two different elastic parameters medium.

The general approximation for P-wave reflection coefficients can be found in several works. The classical for is due to Aki & Richards (1980), which was used in Martins (2006). The approximation provides the reflection coefficient (R) as a function of medium parameters and incidence angles θ_i:

$$R = A + B\, sen^2\, \theta i + C\, tang^2\, \theta_i\, sen\, \theta_i \qquad (6)$$

where, A, B and C are coefficients related to medium parameters (i.e., densities and compressional and shear velocities)

$$A = \frac{1}{2}\left(\frac{\Delta\rho}{\overline{\rho}} + \frac{\Delta V_p}{\overline{V_p}}\right), \qquad (7)$$

$$B = \frac{1}{2}\left[\frac{\Delta V_p}{\overline{V_p}} - 2\left(\frac{\overline{V_s}}{\overline{V_p}}\right)^2\left(2\frac{\Delta V_s}{\overline{V_s}} + \frac{\Delta\rho}{\overline{\rho}}\right)\right], \qquad (8)$$

and

$$C = \frac{1}{2}\frac{\Delta V_p}{\overline{V_p}}, \qquad (9)$$

where:

$\Delta V_p = V_{p2} - V_{p1}$, $\Delta V_s = V_{s2} - V_{s1}$, $\Delta\rho = V_{\rho 2} - V_{\rho 1}$, $\rho = (\rho_2 + \rho_1)/2$, $V_p = (V_{p2} + V_{p1})/2$ and $V_s = (V_{s2} + V_{s1})/2$.

The seismic responses generated in this work are made using normal incidence ($\theta_i = 0$). Therefore the equation 6 can be written as:

$$R = A = \frac{1}{2}\left(\frac{\Delta\rho}{\overline{\rho}} + \frac{\Delta V_p}{\overline{V_p}}\right). \qquad (10)$$

Rearranging equation 10, we have:

$$R = \frac{Z_2 - Z_1}{Z_1 + Z_2}, \qquad (11)$$

where, Z_1 is the contrast acoustic impedance of the overlying layer and Z_2 is the acoustic impedance of the underlying layer.

The amplitude of seismic reflections can be altered by three main geologic factors (Ruijtenberg et al., 1992). The first is the change in cap rock properties (density, velocity, litology and others). The second one refers to the alterations in reservoirs properties caused by variations in porosity, mineralogy or type of fluid. The last factor is the change in interfaces geometry through fracturing and dips variations. Generally, the properties of cap rocks are constant in large areas, so that the local changes in amplitude are often related to internal variations in reservoirs or in its geometry.

Methodology

First of all, the selection of our geologic models is based on structures of sandstone reservoirs very commonly found in the Brazilian offshore areas. After a little research, we selected two models: wedges (pinch outs) and lenses of sandstones. The second step is the evaluation of seismic and rock physics properties for all the structures present in the model (seal, reservoir and source rocks). For this, we use the information presented in published studies, like Castagna and Backus (1993) to decrease uncertainties. Only for reservoir rocks we infer the seismic velocities (compressional and shear) and density using an algorithm in MATLAB code. This is based on the Gassmann fluid substitution and it uses Gassmann's equation to predict the seismic properties of a saturated rock in a specific fluid (gas, oil or water). The data obtained are coherent because it is validated by the research specified above. Finally, we use seismic modelling software called SEISMOD (MacPherson, 2006). It applies the convolucional model in normal incidence of rays and it allows to choose the frequency of wavelet. In this case we choose Ricker wavelet of 30 Hz, because it is the frequency more common in marine seismic data. In this program we can combine the geologic models with the data, from the algorithm and the literature, and it generates the synthetic seismic sections for reservoirs contending gas, oil and water.

Results

Although considered a very simple model, the wedge model is for reproducing realistic situations found in the nature, such as stratigraphic thinness and pinch out of sand layers (Harvey & MacDonald, 1990). Besides, this geologic model and the lenses model, help to understand the problem of the vertical resolution faced by the seismic interpreters, very common in turbiditic reservoirs in deep waters.

The wedge model in figure 1 is located at 2000 m depth, having a wedge thickness of 250 m. This depth is considered to be zero time in the seismic sections. Above the wedge there is a shale layer and below, there is a limestone layer whose properties are in the Table 2. The wedge is saturated by three fluids: gas, oil and water, respectively (see figure 1), the thickness of sandstone layer saturated with each fluid is approximately 83 m. In this model, the shale layer works as a stratigraphic trap, imprisoning the hydrocarbon.

Table 2: Values of layers' seismic properties.

Properties	Shale	Sandstone with gas	Sandstone with oil	Sandstone with water	Limestone
Vp (m/s)	3800	2904	3000	3282	3600
ρ (gm/c^3)	2,34	2,14	2,23	2,29	2,4
σ (Poisson ratio)	0,24	0,08	0,2	0,32	0,18

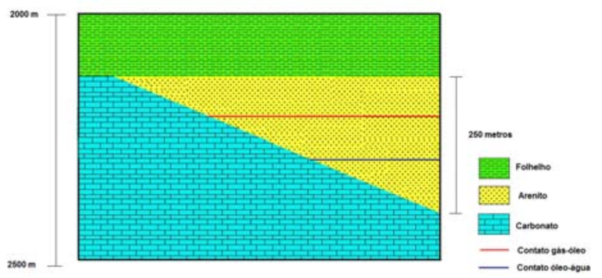

Figure 1: Wedge geologic model.

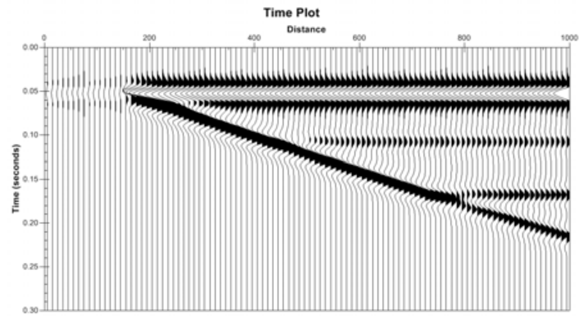

Figure 2: Synthetic seismic section of the wedge model.

Analyzing the seismic section in figure 2, we can notice the contrasts in acoustic impedance (product of velocity and density) that represent changes in seismic characteristics. The amplitude of seismic anomaly, provided by reflection coefficient, is bigger when the difference between the impedances of two juxtaposed layers is more discrepant.

The first amplitude anomaly has negative polarity, due to the passage of seismic wave from a high velocity material to a lower velocity medium (shale to sandstone with gas). The opposite, that is, positive polarity (black peaks), can be observed in the last anomaly, when wave passes from a lower velocity material to higher velocity layer (from sandstone with water to limestone). On the top left-hand corner of figure 2, we realize a small anomaly of amplitude with negative polarity, derived from a little contrast of acoustic impedance between the shale and the limestone.

In the inner part of the reservoir, we have two positive amplitude anomalies, with the first greater than the second. The first positive amplitude represents the transition from sandstone with gas to sandstone with oil. The second anomaly occurs when the wave passes from sandstone with oil to sandstone with water. The intensity of these anomalies is different, because their velocities variation increase (Table 1), implies in the increase of acoustic impedance. Another example is that the change in anomaly intensity can be seen in the base of the sandstone reservoir. The intensity goes up according to the increase in velocity's variation.

Another important point that can be visualized with this model, is the problem with the vertical seismic resolution. The analysis of this factor is fundamental when we have thinness or small structural features. After determining the limit of thickness that is given by one quarter of wave length approximately, the pulses interfere each other and the end of layers is unable to be identified. This resolution problem damages the accuracy in the estimation process of hydrocarbon volume in the reservoir. To solve this, it is necessary to use the geophysical method of mesoscale, i.e., well-log data.

The other selected geologic model represents a complex model with lenses of sandstone reservoirs (Brito, 1986). This example makes our simulation more realistic, because it is based on real seismic sections stacked and well-log information. The lithologies are located at 2000 m depth and the reservoir has 50 m of thickness. One of the reservoir body boundaries is characterized by a typical standard truncation. This is very common in petroleum reservoirs, working as a trap accumulating with hydrocarbons.

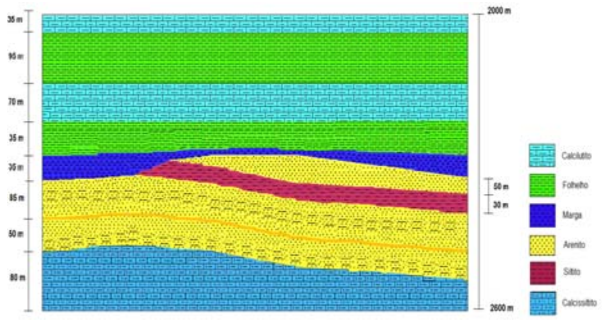

Figure 3: Lenses of sandstone model.

The seismic properties for this model are demonstrated on Table 3 and 4. The magnitudes of the seismic properties are extracted from Brito (1986), the Poisson ratio from Domenico (1976) and Ostrander (1984) and density from the Gardner's Equation.

Table 3: Layers' seismic properties.

Thickness (m)	Vp (m/s)	ρ (gm/cc)	σ (Poisson ratio)
35	3050	2.26	0.26
95	2900	2.23	0.23
70	3200	2.29	0.26
30	2900	2.23	0.23
35	3200	2.29	0.22
35	3500	2.35	0.26
50	Sandstone values with desired fluid (table 4)		
30	3200	2.29	0.15
90	3300	2.32	0.15
50	3050	2.26	0.15
80	4600	2.51	0.26

Table 4: Reservoirs' seismic properties

Reservoir	Sandstone with gas	Sandstone with oil	Sandstone with water
Vp (m/s)	2000	2900	3050
ρ (gm/cc)	2.0	2.27	2.29
σ (Poisson ratio)	0.08	0.20	0.32

The behaviour of reflection response in a certain interface depends, besides seismic and physics properties, on the fluid contents in the rocks. With this in mind, simulations are made in three different fluids in the reservoir, using the same lithologic and stratigraphic characteristics. This has been done in order to visualize how the presence of fluids can change the seismic response (see figures 4, 5, 6).

It is visible in the gas reservoir (figure 4) that the intensity of amplitude anomalies are stronger. It is verified by the greater contrast in acoustic impedance that exists between saturated rock and the rock above. In figure 5, the seismic response in the oil reservoir can be reasonably discerned. Concerning the reservoir with water in figure 6, the amplitude anomalies have low intensity, making the delimitation of the reservoir very hard.

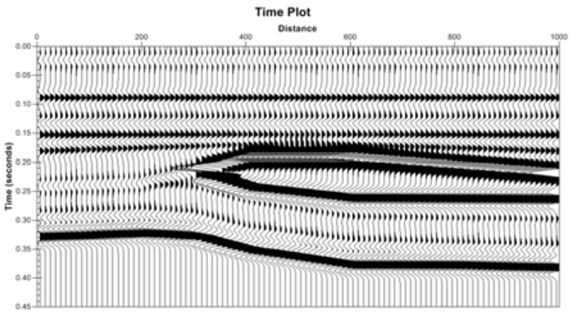

Figure 4: Synthetic seismic section with gas.

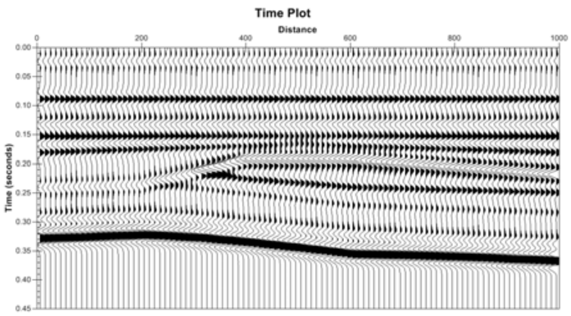

Figure 5: Synthetic seismic section with oil.

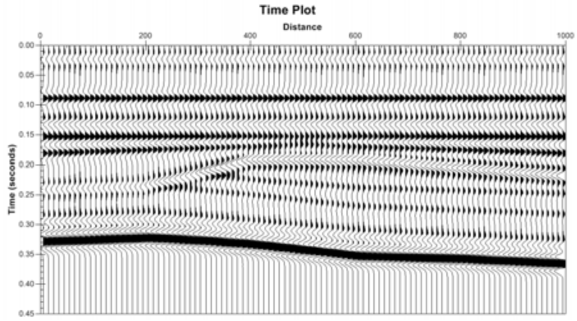

Figure 6: Synthetic seismic section with water.

Simulations involving fluid contacts are done with the geologic model in figure 7. In this case we selected the three fluids at same time in the reservoir. The first contact (red line) is gas-oil and the second one (blue line) is oil-water.

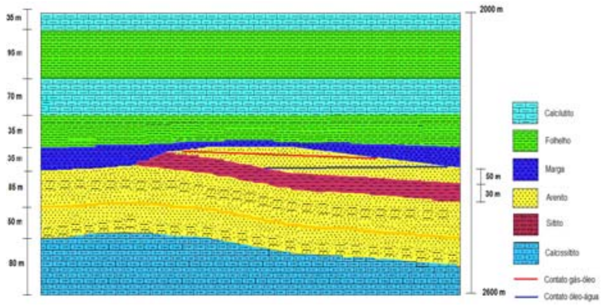

Figure 7: Geologic model with fluids contacts.

The synthetic seismic section in figure 8 shows us that there is a reservoir, since we have a greater contrast of impedance. However, in comparison to the other previous simulated seismic sections, the accuracy for delineating the reservoir is small. The contacts of fluids are unable to be clearly identified in the reservoir rock, indicating that the thickness of layer is inferior to the limit of vertical seismic resolution.

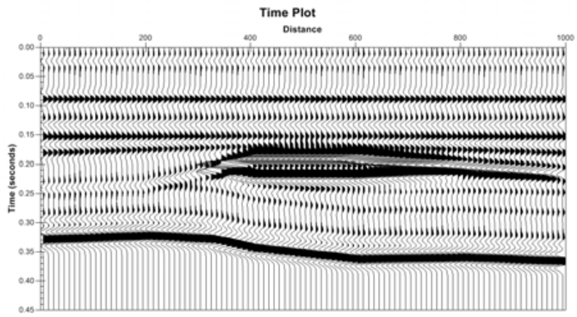

Figure 8: Synthetic seismic section with gas, oil and water.

Conclusions

The results of this study confirm that the amplitude of seismic reflections depends on the elastic constants of the materials, angle of incidence and on the thickness of layers. The elastic constants are functions of lithologic and mineralogic in the area characteristics. Besides this, they are related to the types of fluids and their characteristics in the porous rock. The previous knowledge about the amplitude anomalies behaviour, by numeric simulation, gives us more references and dynamism when we analyse a real seismic data.

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