Modeling 4-D seismic responses in a gas reservoir

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Summary

It is well known that differential pressure change will induce time-lapse seismic attribute changes by acting on both the rock matrix and the pore fluids. It would be very helpful for seismic amplitude interpretation if we can separate the time lapse seismic attribute changes induced by rock matrix and pore fluids respectively. Based on petrophysical data and laboratory rock physics data from a North Sea gas reservoir, this study showed that the overall time-lapse seismic responses can be approximated by the arithmetical sum of time-lapse seismic property change induced by dry rock matrix and by pore fluids respectively. Identify and separation of the differential pressure effects could bring a new insight regarding discrimination between pore pressure and saturation changes.

Introduction

Differential pressure is the difference between the confining pressure and pore pressure. Usually the confining pressure of a reservoir is assumed unchanged while the pore pressure will vary with depletion or injection. Change of differential pressure has effects on both the dry rock bulk moduli and pore fluids modulus. The effect on rock matrix is often overlooked when fluid substitution is applied to model the time lapse seismic property changes.

Our study shows that the differential pressure effect on rock matrix is significant for gas reservoir and it dominates the time lapse seismic attribute changes before water invasion. Also we found a way to separate time-lapse seismic property change induced by dry rock matrix and by pore fluids respectively. So it is possible to derive the time lapse seismic properties attributed only to fluid property changes. After including differential pressure effect, the time lapse AVO crossplots show clear pore pressure trend distinctly different from water saturation trend. It might be plausible to discriminate between pore pressure and saturation changes using time lapse AVO analysis.

Forward Modeling Methodology

First we need to set up the relation between differential pressure and dry rock moduli using the lab measured data. 42 core samples from the target gas field were measured to find this relationship. The original pore pressure is 42.6 MPa, the confining pressure is estimated to be 75.6 MPa, and the other fluid properties at the original conditions can be found from the PVT report. From the log data, we summarized a representative gas reservoir model with original P-wave velocity, S-wave velocity, porosity and water saturation. The original fluid properties are known, so we can invert the dry rock moduli using Gassman's equation. With depletion or injection, the pore pressure and fluid property will change, and so do dry rock moduli. The fluid property change can be predicted by our FLAG program, and the dry rock moduli change can be predicted by empirical dry rock moduli – differential pressure relations. With the changed dry rock moduli and fluid properties, again using Gassman's equation, we can predict the seismic property changes at later times.

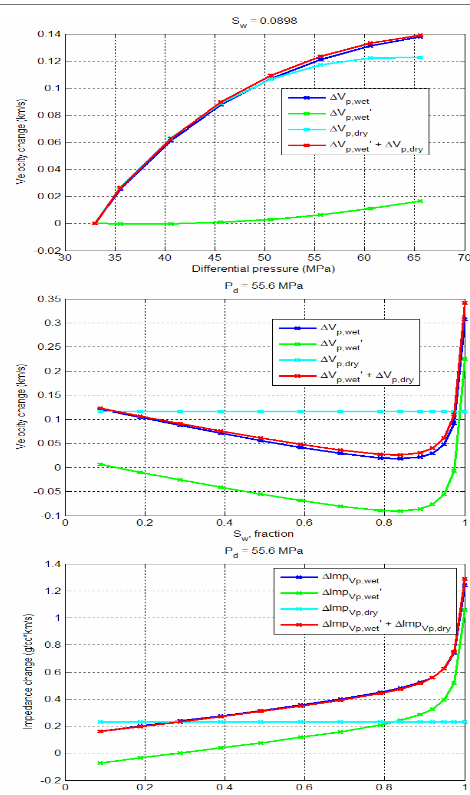


Figure 1: Time lapse seismic property change
Top: P-wave velocity changes with differential pressure (constant water saturation);
Middle: P-wave velocity change with water saturation (constant differential pressure);
Bottom: P-wave impedance change with water saturation (constant differential pressure)

Separation of Differential Pressure Effect

For the typical gas reservoir model, the dry rock moduli at original conditions are inverted using Gassman's equation. To evaluate the different pressure effect, we first apply fluid substitution with considering differential pressure effects both on dry rock matrix and pore fluids, the P-wave velocity change calculated is called $\Delta V_{p,wet}$ (all the seismic property changes are relative to the original reservoir conditions); and then we apply fluid substitution again without considering the differential pressure effects on dry rock matrix. The P -wave velocity change thus calculated is called $\Delta V_{p,wet}'$. $\Delta V_{p,dry}$ is derived from the dry rock moduli - different pressure relation based on laboratory measurement. Similar terminology applies to P-wave impedance change.

From Figure 1 it can be seen that $\Delta V_{p,wet}$ is approximately equal to ($\Delta V_{p,wet}' + \Delta V_{p.dry}$). This means that the overall P-wave velocity change of the reservoir rock can be approximated by the arithmetical sum of the dry rock P-wave velocity change and P-wave velocity change induced by the fluid property change (without considering differential pressure effect on rock matrix).This relation also applies to P-wave impedance (as shown in bottom of Figure 1). Actually this relation also applies to shear velocity and shear wave impedance, we have limited space to show the results.

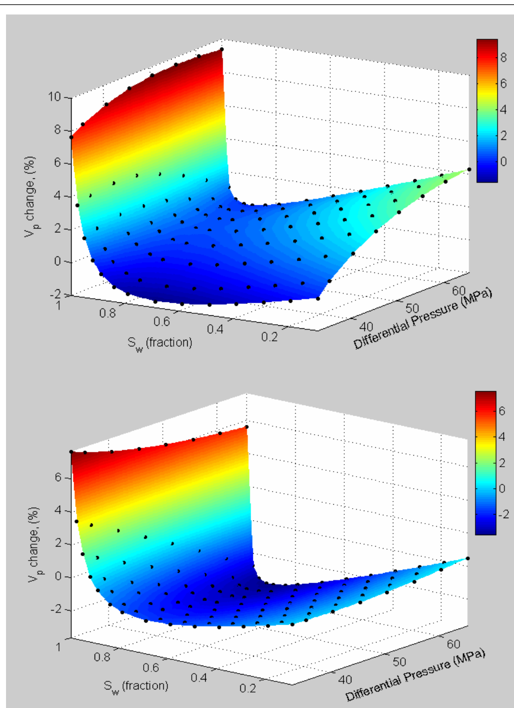


Figure 2: P-wave velocity change with considering the differential pressure effect on dry rock matrix (top) and with this effect being subtracted (bottom).

If we change the water saturation and pore pressure at the same time, and apply the methodology introduced above, we can get a comprehensive picture of how the seismic properties of the reservoir change with respect to water saturation and pore pressure (Top of Figure 2 and Figure 3).

The velocity change is quite complicated when both the pore fluid property change and the differential pressure effect on dry rock moduli are included. If we apply the approximation statement made earlier in this section and subtract the differential pressure effect on dry rock matrix, then what left is the time-lapse seismic property change due only to fluid property change (bottom of Figure 2 and figure 3). It can be seen from Figure 2 and Figure 3 that after taking off the differential pressure effect on dry rock matrix, both P-wave velocity change and P-wave impedance change are much less complicated and will make it easier to invert the water saturation change from time lapse seismic data.

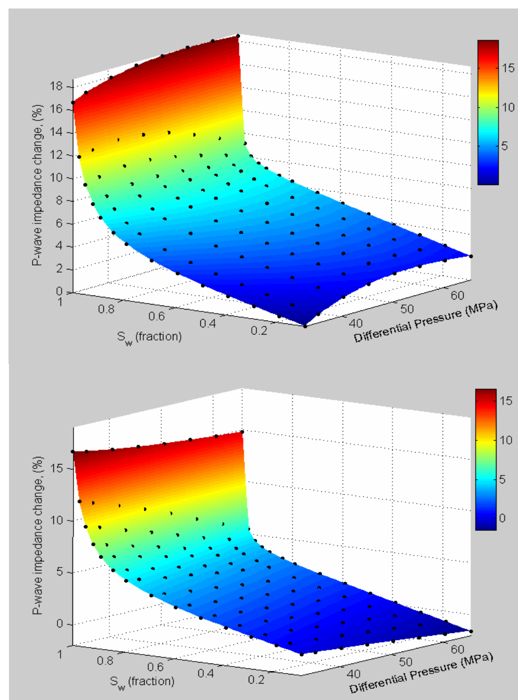


Figure 3: P-wave impedance change with considering the differential pressure effect on dry rock matrix (top) and with this effect being subtracted (bottom).

Comparing the top and bottom plots in Figure 2, we can see that the differential pressure effect is significant. It dominates the time lapse velocity changes when the water saturation is low. If the differential pressure effect on rock moduli is ignored during inversion, we might misinterpret the velocity increase as water invasion, but actually it is caused by differential pressure effect.

Comparing the bottom plots of Figure 2 and Figure 3, we can see that the time lapse P-wave impedance change monotonically increases with water saturation. So it is better to use time lapse impedance change to quantitatively invert water saturation.

Error Analysis

We have stated in last section that the overall velocity change of the reservoir rock can be approximated by the arithmetical sum of the dry rock velocity change and wet rock velocity change induced by pore fluids property change (assuming rock matrix moduli unchanged). In order to further validate this statement, we try to analyze which factors control the approximation error.

The error is defined as $(\Delta V_{p,wet}' + \Delta V_{p,dry}) - \Delta V_{p,wet}$. The top plot in Figure 4 is error analysis for the typical reservoir model. We can see that the error approximately increases linearly with square root of the fluid bulk modulus. The biggest error occurs at full water saturation (about 35 m/s), but the overall velocity change is also the biggest (more than 300 m/s for this model) at this point, so the relative error is still small.

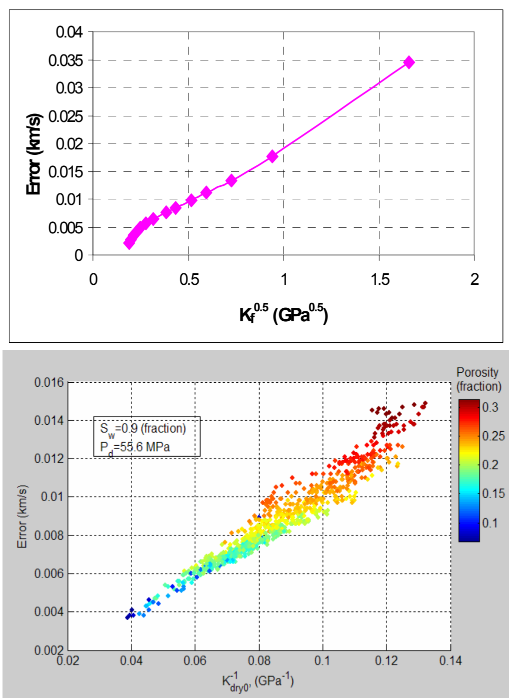


Figure 4: Error analysis for the typical reservoir (top) and log data (bottom). The error is defined as $(\Delta V_{p,wet}' + \Delta V_{p,dry}) - \Delta V_{p,wet}$.

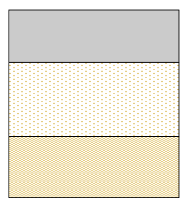
The bottom plot of Figure 4 is error analysis based on the log data. K_{dry0} is the dry bulk modulus at original reservoir conditions for each sample depths within reservoir. It is inverted from the logging data. Using the procedure introduced before, we apply fluid substitution assuming the pore pressure decreases to 20 MPa (differential pressure increases to 55.6 MPa) and the water saturation increases to 90%, with and without consideration the differential pressure effect on rock matrix respectively. The "error" for each depth point within the reservoir section can be calculated and are plotted with the reciprocal of K_{dry0} as x-coordinate.

From this plot (bottom of Figure 4) we can see that the error generally increases linearly with the reciprocal of the original dry bulk modulus. The porosity has indirect effect on the error by affecting the dry rock moduli. So the loose sand will have bigger error, but remember it also has bigger velocity change.

In conclusion the approximation statement we made is generally valid, and the error is controlled by the relative difference between the fluid modulus and the original dry rock moduli, the bigger the difference, the smaller the error.

Time-lapse AVO Analysis

Based on the log data, a model for time lapse AVO analysis is summarized as in Figure 5.



	Vp, km/s	Vs, km/s	ρ_b, g/cm³
Shale	3.9107	2.3073	2.5295
Upper Sand*	3.2129	1.9827	2.0706
Bottom sand	3.4927	2.1498	2.2481

* These parameters will change with differential pressure
(Water saturation of the bottom sand unchanged)

Figure 5: Time lapse AVO analysis model

The upper sand is the producing reservoir; the bottom sand is also gas-bearing, but it was reported that the gas can not come out because the bottom sand has smaller porosity and is complicated by heterogeneous mud barrier and other factors. So we assume the pore pressure and water saturation of the bottom sand do not change with time. Changing both the differential pressure and water saturation of the upper sand, we can calculate the corresponding velocity and density changes and model time lapse AVO variation for both the upper and lower interfaces (Figure 6 and Figure 7).

In figure 6, PR represents Poisson reflectivity and is defined (Hilterman 2001) as:

$$PR = \frac{(\sigma_2 - \sigma_1)}{(1 - \sigma_{avg})^2}$$

where σ_1 is Poisson's ratio of the upper formation, σ_2 is the Poisson's ratio of the lower formation, and σ_{avg} is the average to the two Poisson's ratios.

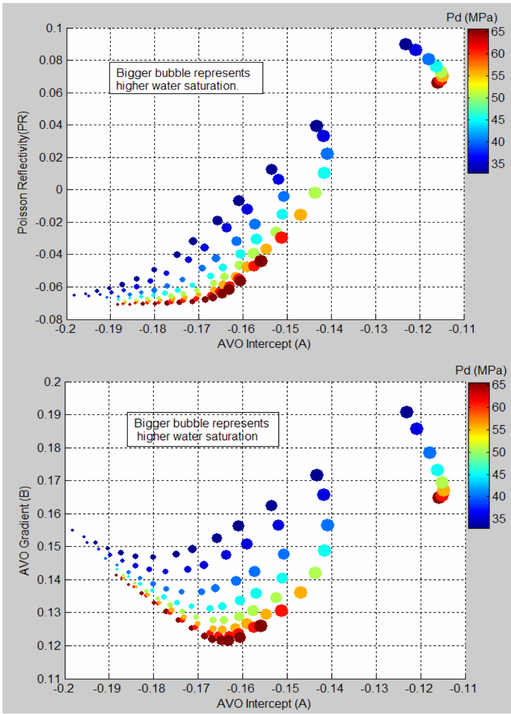


Figure 6: AVO crossplots for the upper interface

From Figure 6 and Figure 7 we can see that the differential pressure effect on time lapse AVO crossplots is significant, especially in the A-B crossplot. The differential pressure effect trend is distinctly different from that of water saturation. It is also noticed that the PR-A crossplot has much better sensitivity to water saturation change. So these two kinds of time lapse AVO crossplots are complementary and can be used together to discriminate between pore pressure and saturation change.

Conclusions

The differential pressure effect on dry rock matrix might have significant effect on time lapse seismic property changes. We found that the overall seismic attribute changes of the reservoir rock can be approximated by the arithmetical sum of the dry rock matrix property change and the wet rock property change caused by pore fluids property change (assuming rock matrix moduli unchanged). So that we can subtract the differential pressure effect on rock matrix from the overall seismic property changes and get the seismic property change attributed only to fluid property change. The differential pressure effect also has distinct trend on time lapse AVO crossplots, which might be used to discriminate between pore pressure and saturation change.

Reference

Fred J. Hilterman, 2001, Seismic amplitude Interpretation, Distinguished Instructor Series, No. 4

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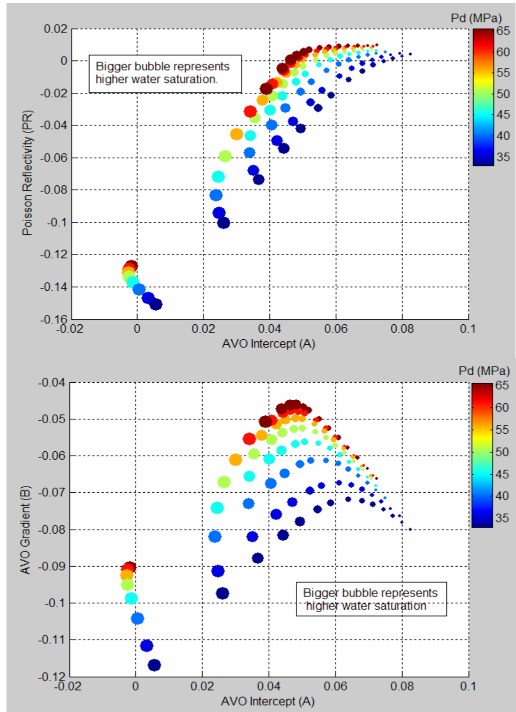

Figure 7: AVO crossplots for the lower interface

EDITED REFERENCES

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REFERENCES

Hilterman, F. J., 2001, Seismic amplitude interpretation: Distinguished Instructor Series, no. 4.