RESEARCH PROPOSAL

Effects of scales and extracting methods on quantifying quality factor Q

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ABSTRACT

The attenuation values obtained in the lab are usually larger than those measured in the field. To understand this inconsistency, I propose to model attenuation from rock properties and reflection seismic data, and then compare their results. A gas well is used here for providing the rock properties and seismic properties. The preliminary results show that scaling is one of the factors that lower the attenuation values obtained from the field. In the future work, by adjusting more parameters (e.g., the frequency band), checking the received energy in the seismic data, and comparing those two Q models, I will understand more of the key influencing factor on the inconsistency, which helps optimize the acquisition design and choose a suitable method of measuring Q. Those conclusions can be used in practice and help understand the reservoir characterization.

INTRODUCTION

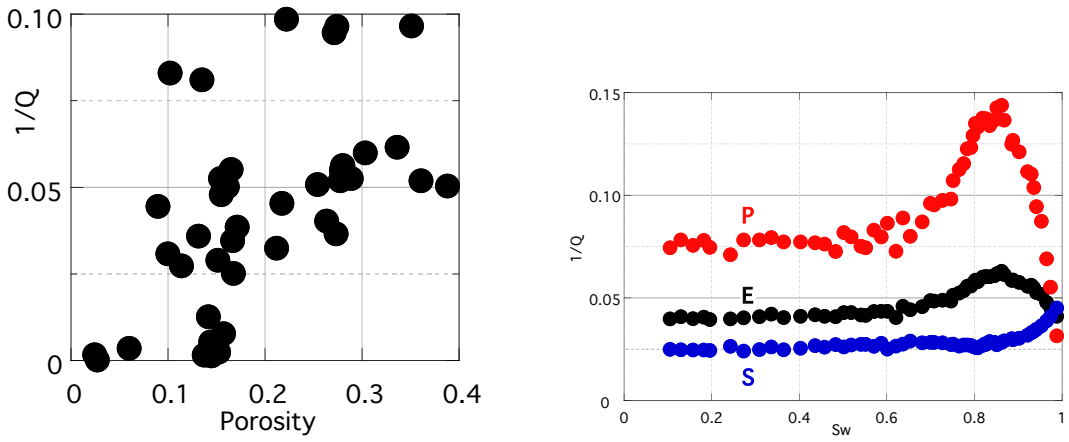
Problem Statement

Consistent and accurate field measurements of Q are rare due to practical difficulties of extracting attenuation from reflection seismic data, crosswell, VSP, and full waveform borehole data. These field measurements are also inconsistent with the lab measurements.

Q values estimated from seismic events are usually very high. In-situ Q in marine sediments has been estimated to be 30 in wet sand and as high as 100 and even 400 in silt and clay. Kvamme and Havskov (1989) estimate Q about 950 at 10 Hz while in Lilwall (1988), Q is between 100 and 200 in the upper 3 km of the crust. VSP data have been used to calculate Q exceeding 300 in basement rock at depths below 1.8 km. Crosswell tomography has been used to estimate attenuation in the 200-2000 Hz frequency range. Q is between 30 and 50 in soft (Vp between 2.6 and 3.0 km/s) sand/shale sequence and reaches 100 in chalk and limestone. A Q of 33 has been estimated from a high-resolution 2D seismic data over a Florida carbonate high-porosity aquifer system where VP is between 2 and 3 km/s and density is about 2 g/cc.

The attenuation values obtained in the lab are usually larger than those measured in the field. A study by Klimentos (1995) is one of the few relevant to hydrocarbon exploration. It reports, based on sonic waveform analysis, that Q falls between 5 and 10 in gas sandstone of about 12% porosity (Q^{-1} between 0.1 and 0.2) while it may easily exceed 100 ($Q^{-1} < 0.01$) in oil- and water-saturated intervals. Attenuation is large in rock with partial gas saturation and small in liquid-fill rock. Other examples also reveal that the lab-measured attenuation in the gas rock is small, as shown in Figure 1.

Although those inconsistencies are observed by the above studies, their explanations have not been provided. One possible reason is that the seismic survey are usually conducted in a large spatial range. Hence the signal may not reach the target or receivers after propagating through a strong absorptive medium. Furthermore, the large scale or the low frequency in the seismic survey spatially averages the attenuation, and hence lower the estimated attenuation values. In addition, different methods used for the Q model building is another explanation for the different results estimated from the lab and the seismic measurements. Therefore, if we could fully understand the influencing factor on the inconsistency, we could optimize the acquisition parameters, choose a suitable measurement of Q, and hence help accurately predict and interpret the reservoir.



(a) (b)

Figure 1: (a) Ultrasonic laboratory data on wet sandstone. The inverse quality factor from Klimentos and McCann (1990) is plotted versus porosity. (b) Resonance bar attenuation data in Massillon sandstone of 23% porosity Murphy (1982). The inverse quality factor is plotted versus water saturation. Frequency is between 300 and 600 Hz. Black, blue and red curves show E-, S- and P- wave respectively.

PROPOSED SOLUTION

I propose to model attenuation from both the rock properties and the reflection seismic data, and then compare their results to understand the inconsistency between the lab and field measurements. First I build Q model from the rock properties provided by a gas well. The gas well contains both high attenuation and low attenuation zones. The high attenuation zone exists in the partially saturated rock where the viscous fluid water moves in and out of the gas-saturated pore space; while the low attenuation zones exist in the saturated regions. Then a correspondant seismic data is generated from the seismic properties provided by this well log. Another Q model is reconstructed from this synthetic seismic data and will be used later to compare with the Q model from the rock properties. By adjusting the parameters (e.g. scales),

checking the received energy in the seismic data, and comparing the low Q and high Q zones in those two Q models, I will understand the key influencing factor on the inconsistency, which helps optimize the acquisition design and choose a suitable method of measuring Q. Those conclusions can be used in practice and help understand the reservoir characterization.

THEORY

Since the Q modeling from the seismic reflection data has been presented in my primary proposal, I mainly present the method of Q modeling from the rock properties here. This section contains three parts: attenuation at partial saturation (Dvorkin and Mavko, 2006), attenuation in wet rock (Dvorkin and Uden, 2004) and upscaling attenuation from the well to the seismic level.

To quantify Q, the physical principle is used to link attenuation to the changes in the elastic modulus versus frequency. A simple illustration of this link is for an ideal viscoelastic system, the standard linear solid:

$$Q^{-1}_{\max} = \frac{M_H - M_L}{2\sqrt{M_H M_L}}. \tag{1}$$

where $Q^{-1}_{\max}$ is the maximum inverse quality factor; M_H is the compressional modulus at very high frequency; and M_L is the compressional modulus at very low frequency. The compressional modulus is the product of the bulk density and P-wave velocity squared. This equation provides the upper bound for attenuation without addressing its frequency dependence. Therefore, the problem is reduced to finding M_H and M_L.

Attenuation at partial saturation

The reaction of rock with patchy saturation to loading by the elastic wave depends on the frequency. If it is low and the loading is slow, the oscillations of the pore pressure in a fully liquid-saturated patch and partially saturated domains next to it equilibrate. The patch is "relaxed". Conversely, if the frequency is high and the loading is fast, the resulting oscillatory variations of pore pressure cannot equilibrate between the fully saturated patch and the domain outside. The patch is "unrelaxed". Therefore, I can compute the modulus of the "relaxed" and "unrelaxed" patch to calculate the Q value at partial saturation

Attenuation in wet rock

The viscous-friction losses may also occur in wet rock where elastic heterogeneity is present. Deformation due to a stress wave is relatively strong in the softer portion of

the rock and weak in the stiffer portion. The spatial heterogeneity in the deformation of the solid frame forces the fluid to flow between the softer and stiffer portions. Such crossflow may occur at all spatial scales. Therefore, I obtain Q value in wet rock by computing the modulus in the softer portion and the stiff portion of the rock.

Upscaling Attenuation

If the amplitude of the input signal reduces to $A_1 = A_0 \exp(-\alpha_1 x_1)$ after the wave travels distance x_1 with attenuation coefficient α_1, it further reduces to $A_2 = A_1 \exp(-\alpha_2 x_2)$ after it travels distance x_2 with attenuation coefficient α_2. As a result,

$$A_2 = A_0 e^{-(\alpha_1 x_1 + \alpha_2 x_2)} \equiv A_0 e^{-\alpha(x_1+x_2)}, \tag{2}$$

where α is the average (upscaled) attenuation coefficient over distance $x_1 + x_2$. As a result,

$$\alpha = \alpha_1 \frac{x_1}{x_1 + x_2} + \alpha_2 \frac{x_2}{x_1 + x_2}, \tag{3}$$

which means that the attenuation coefficient has to be upscaled arithmetically

Strictly speaking, the inverse quality factor cannot be upscaled arithmetically because $Q^{-1} = \alpha V/\pi f$ and both V and f may change from an interval to an interval. A correct expression for averaging the inverse quality factor over a long interval is

$$\overline{Q^{-1}\frac{\pi f}{V}} = \left\langle Q^{-1}\frac{\pi f}{V} \right\rangle. \tag{4}$$

The average (upscaled) inverse quality factor $\overline{Q^{-1}}$ can be defined through the average velocity $\overline{V}$ and average attenuation coefficient $\overline{\alpha}$ as

$$\overline{Q^{-1}} = \overline{\alpha}\overline{V}/\pi f, \tag{5}$$

where $\overline{\alpha}$ is the arithmetic average of the attenuation coefficient and $\overline{V}$ is the upscaled velocity which should be calculated from the Backus (harmonic) average of the elastic modulus.

WORK COMPLETED

A gas well, as shown in Figure 2, is used here for providing the rock properties and seismic properties. In this section, I will present the Q model reconstructed from the rock properties; while the Q model estimated from the seismic properties belongs to my future work. Figure 2 shows that the water saturation at the depth from 1.25km -1.27km and 1.31 km-1.32 km is lower than the surrounding areas. The low water saturation indicates the gas sand. In addition, since gas is lighter and softer than water, the density and P wave velocity, as shown in Figure 2(3) and (6) respectively, are lower in the gas-saturated rock.

To reconstruct the Q model, the compressional modulus of the mineral phase (clay and quartz) Ms is required. I use Hill's average of the two minerals to compute Ms and show it in Figure 3. Then, I compute the Q^{-1} models in both partial saturated rock and wet rock respectively and combine them in Figure 4(a) as shown in the black curve. The result shows that attenuation is high in the gas sand, since the viscous-flow friction is strong in partially saturated rock where the viscous fluid water moves in and out of the gas-saturated pore space.

To test whether the large scales of the seismic survey lower the measured Q value, I upscale the well into a larger scale with 10m interval and 30m interval respectively. Although the inverse quality factor cannot be strictly upscaled arithmetically, it can be approximately averaged arithmetically, because both velocity and attenuation during each interval are usually very smooth in the seismic study. The red and blue curve in Figure 4(a) show Q^{-1} model after upscaling. The results show that larger scales further lower the measured attenuation value. Therefore, we could conclude that scaling is one of the key factors that influences the inconsistency mentioned in the previous sections.

However, even though the peak of the curves in Figure 4(a) are different, they all approximately points out the same position of the gas rock. From this point of view, the upscaling does not affect the reservoir characterization. In addition, I calculate the cumulative sum of these three curves in Figure 4(a) and show them in Figure 4(b). The results show that the upscaling does not influence the accumulated attenuation along the depth. Further conclusion of this result needs to be explored in the future.

FUTURE WORK

Q modeling from seismic reflection data

I will generate a set of seismic data from the seismic properties provided by this well log. Then I will reconstruct the Q model from this synthetic dataset to compare with the Q model from the rock properties. By adjusting more parameters (e.g. the frequency range), I will understand more of the key influencing factor on the inconsistency, and hence optimize the acquisition design.

Test on the field data

After studying on this gas well, I will look for a proper field data which contains both real well log and field seismic reflection data to validate my conclusions.

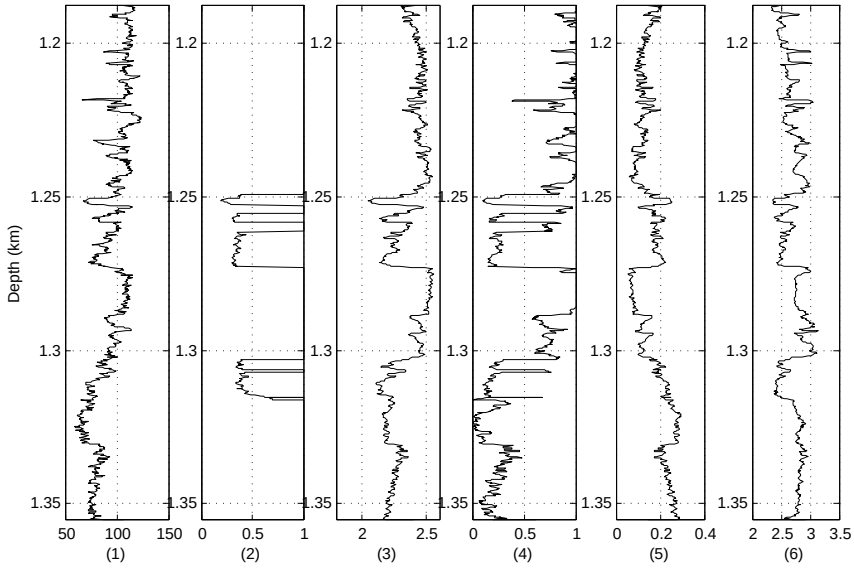


Figure 2: Depth plot using the input gas well data: (1) gamma ray; (2) water saturation; (3) density (unity:g/cc) (4) clay content; (5) porosity; (6) compressional velocity (unit:km/s).

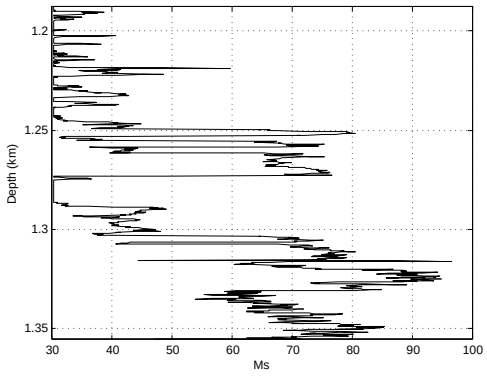
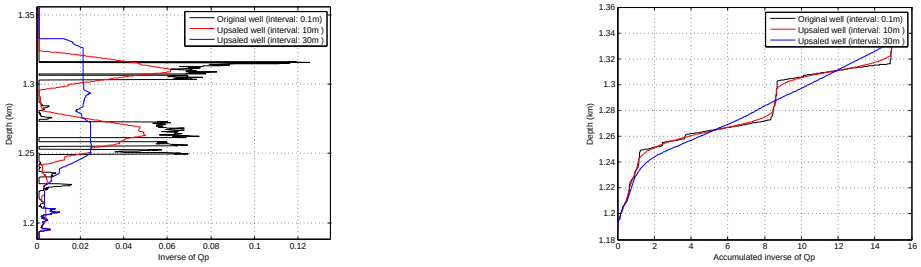


Figure 3: The compressional modulus of the mineral phase, which is computed using Hill's average of the two minerals and used for Q reconstruction.



(a) (b)

Figure 4: Given the gas well in Figure 2: (a) The inverse of Q. The black curve shows the Q^{-1} model reconstructed from the rock properties provided by the gas well in Figure 2. The red and blue curve show the upscaled Q^{-1} model averaged arithmetically from the upscaled well with 10m interval and 30m interval respectively. (b) The cumulative sum of the curves shown in Figure 4(a) with the same color code.

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