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# CUMULATIVE SEISMIC ATTRIBUTE FOR $\phi h$ DETERMINATION

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## Abstract

Porosity in thin sub-resolution layers cannot be correctly mapped by directly applying rock physics impedance-porosity transforms to seismic impedance volumes simply because the upscaled seismic impedance often differs from the actual fine-scale values. Instead, we propose to map the product of porosity and thickness or, more precisely, the total pore volume of the reservoir. This cumulative measure of porosity can be related, by means of rock physics, to a new class of seismic attributes introduced here. These are cumulative attributes (CATTS) which are calculated, for example, by an integration of a seismic impedance anomaly along the seismic trace. While the seismic impedance (acoustic and elastic alike) can be, simply speaking, estimated by integrating the trace, CATTS are estimated by integrating the trace repeatedly. This new class of seismic attributes potentially can be used in many geological environments for the purpose of mapping cumulative (or integrated) rock properties from seismic. Below we give a simple synthetic example to illustrate the concept.

## Introduction and Problem Formulation

Several empirical and theoretical relations between velocity and porosity, or the P-wave impedance and porosity, have been established in rock physics. These relations often depend on the geologic age of the sediment and/or its texture but are generally well-defined and universal within a rock type across various geographic areas and basins (e.g., Dvorkin et al., 2002). An example of an impedance-porosity relation for unconsolidated high-porosity sand is given in Figure 1 (left) where well log data from gas- and oil-sand intervals in a North Sea well are plotted and matched by theoretical curves that come from the uncemented sand/shale model of Dvorkin and Nur (1996).

One practical application of such rock physics transforms is synthetic seismic forward modeling where porosity, lithology, and/or fluid in a well are perturbed, corresponding changes in the elastic properties are calculated according to an appropriate rock physics theory, and synthetic traces are generated. The underlying supposition is that if the seismic response is similar, the properties and conditions in the subsurface that give rise to this response are similar as well. Systematically conducted perturbational forward modeling helps create a catalogue of seismic signatures of lithology, porosity, and fluid away from well control and, by so doing, sets realistic expectations for hydrocarbon detection and optimizes the selection of seismic attributes in an anticipated depositional setting (e.g., Dvorkin, 2004).

Another practical application of rock physics is direct mapping of porosity, lithology, and fluid from the seismic impedance. Such mapping has become viable due to the recent advances in impedance inversion methods which allow, in principle, for creating volumes of the acoustic and elastic impedance and even bulk density. If an impedance-porosity transform is established, as shown in Figure 1 (left), for example, it can be directly applied to an

impedance volume to produce a porosity volume.

One problem with such direct porosity mapping is, of course, the difference in the length scale between the well log which is used to establish an impedance-porosity transform (on the order of one ft) and the seismic impedance (tens to hundreds of ft). To illustrate just one aspect of this dichotomy in the scale of investigation consider a pseudo-well that penetrates a soft shale interval with very thick (160 ft or 50 m) gas sand located in the middle (Figure 2). The total porosity in the shale (0.25) as well as the clay content (0.8) are assumed constant throughout the interval. The total porosity in the sand (0.35), clay content (0.05), and water saturation (0.2) are constant as well. The elastic properties in the interval are calculated according to the uncemented sand/shale model of Dvorkin and Nur (1996) and are also plotted in Figure 2.

Let us assume that the seismic frequency is 20 Hz. As a result, for the average P-wave velocity 2.3 km/s, the wavelength is 115 m and the quarter-wavelength is about 29 m (or 100 ft). This is approximately the length scale in the subsurface that will be sampled by the seismic wave, which suggests that relatively thin (sub-resolution) sand intervals cannot be adequately resolved in seismic data. This means that the impedance difference between the sand and surrounding shale that exists at the well-log scale cannot be recovered from seismic impedance inversion. In other words, the impedance anomaly associated with gas sand will be smeared (upscaled) and reduced as a result of elastic averaging with the shale background.

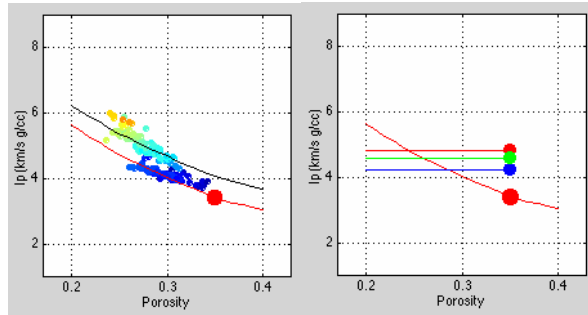


Figure 1. The P-wave impedance versus total porosity. The color-coded symbols in the left frame are from a North Sea well, blue for a gas interval and cyan for an oil interval. The curves are from the uncemented sand/shale model, red for gas and black for oil. The large red symbol is for the gas sand in the pseudo-well shown in Figure 2. The three large colored symbols in the right frame are for the elastic (upscaled) impedance in thin gas sand layers shown in Figure 3. The projection of these impedance values on the impedance-porosity transform will produce strongly underestimated porosity.

A simple way of quantifying the effect of upscaling is the Backus (1962) average that calculates the upscaled effective compressional modulus as the harmonic average of the moduli of the individual layers whose thickness is below the seismic resolution. The compressional modulus is the product of the bulk density and P-wave velocity squared. The density is a volume property and as such should be upscaled according to the arithmetic average. As a result, the upscaled P-wave impedance can be calculated from the Backus-upscaled compressional modulus and bulk density.

This upscaling procedure is used to estimate the seismic-scale impedance in the interval shown in Figure 2 as well as to three other pseudo-wells where the thickness of the gas sand is reduced from the original 160 ft (50 m) to 10 ft (3 m), 20 ft (6 m), and 40 ft (12 m). The resulting upscaled-impedance curves (Figure 3) indicate that the seismic-scale impedance in thin sand may be much smaller than the actual impedance. In the case under examination, only for the very thick sand does the seismic impedance reach the value of the impedance measured in the well. For thinner sand intervals, the seismic impedance values are 4.83, 4.61, and 4.22 km/s g/cc as compared to the measured 3.39 km/s g/cc. If these seismic impedance

values are used in the rock physics transform to map porosity in the sand, the resulting porosity values will be significantly underestimated.

To this end we pose the main question of this study: How to map porosity from seismic impedance in layers that are below seismic resolution?

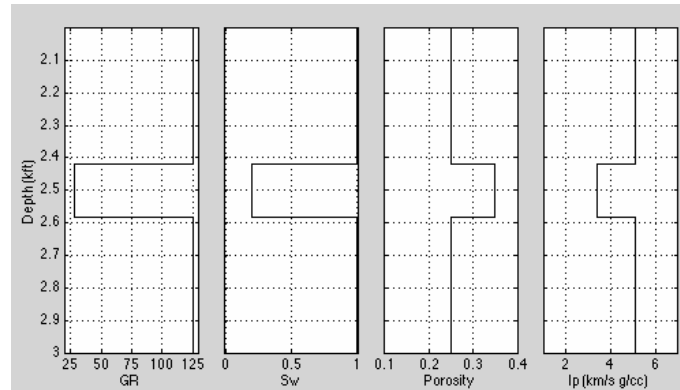


Figure 2. A pseudo-well with thick gas sand. From left to right: GR, water saturation, the total porosity, and P-wave impedance.

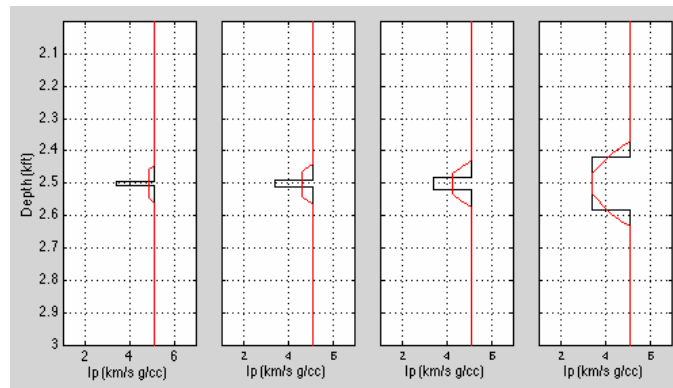


Figure 3. P-wave impedance in three thin gas sand layers (left) and the original thick layer (right). Black is for the original impedance while red is for the seismic (upscaled) impedance.

## Solution

It follows from the results shown in Figures 1 (right) and 3 that the true (fine-scale) porosity cannot be correctly mapped from seismic data simply because the seismic impedance may be different from the true (fine-scale) impedance. Instead we propose to map the product of porosity  $\phi$  and thickness  $h$  ( $\phi h$ ) or, more precisely, the volume integral of porosity in the reservoir which is the same as the total pore volume.

Let us, once again, assume that the porosity in the gas sand is 0.35 and the P-wave impedance is given by the uncemented sand/shale model and is 3.39 km/s g/cc. The *inverse of the impedance* is 0.295 s/km cc/g. The *inverse of the impedance minus the inverse of the background impedance* (impedance in the shale) is 0.1. We call this difference the *anomaly of the inverse impedance*. The straight line in Figure 4 is a cross-plot between  $\phi h$  for this particular porosity and the product of thickness  $h$  and the anomaly of the inverse impedance for thickness varying in the range between 5 and 200 ft. The large blue symbols in Figure 4 are for the product of the thickness and true (fine-scale) anomaly of the inverse impedance in each of the four sand layers shown in Figure 3 versus  $\phi h$  in these layers. As expected, they fall precisely upon the black line.

Let us next integrate the anomaly of the upscaled inverse impedance (the upscaled impedance

is shown by red curves in Figure 3) for each of the four intervals and plot these integrals versus  $\phi h$  as yellow symbols in Figure 4. These yellow symbols almost precisely fall inside the blue symbols and upon the black line. They slightly deviate from the black line because, according to the Backus average, it is the inverse of the compressional modulus that is arithmetically averaged to obtain the seismic-scale modulus. To use this averaging with the anomaly of the inverse impedance is an approximation which produces very small errors in the case under examination but may potentially introduce noticeable discrepancies. Still, we prefer to use the P-wave impedance instead of the compressional modulus because the former is more likely to be extracted from seismic data.

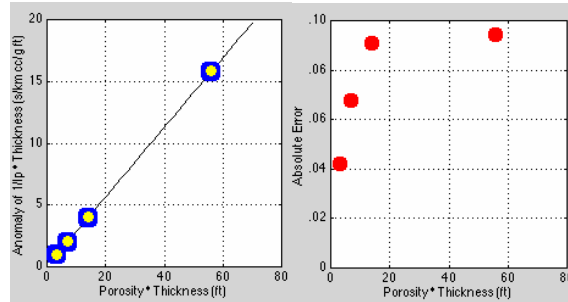


Figure 4. Anomaly of the inverse impedance times thickness versus porosity times thickness (left) and the difference between the values corresponding to yellow and blue symbols (right).

## Discussion and Conclusion

Figure 4 indicates that it is possible to map  $\phi h$  (instead of  $\phi$ ) if a cumulative seismic attribute which, in this case, is the integral of the anomaly of the inverse impedance within the reservoir, is used instead of the impedance. The line in Figure 4 is a rock physics transform between this seismic attribute and cumulative pore volume relevant to the case under examination.

This is a new class of seismic attributes, the cumulative attributes (CATTS), which conceptually, come from the repeated integration of the reflectivity series or, approximately, of the seismic trace. We envision that CATTS can be constructed in different ways for different situations, for the acoustic and elastic impedance alike, in order to map different cumulative reservoir properties.

Implementing CATTS with real seismic data and even synthetic seismic traces will be challenging. Nevertheless, we believe that the concept of this new class of seismic attributes is a solution to the problem of downscaling inherent in mapping reservoir properties from seismic data.

The principle offered here is to map *cumulative* reservoir properties through *cumulative* seismic attributes.

## References

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