

Exploration Vs Development Geophysics

Why is Development Geophysics So Much More Quantitative?

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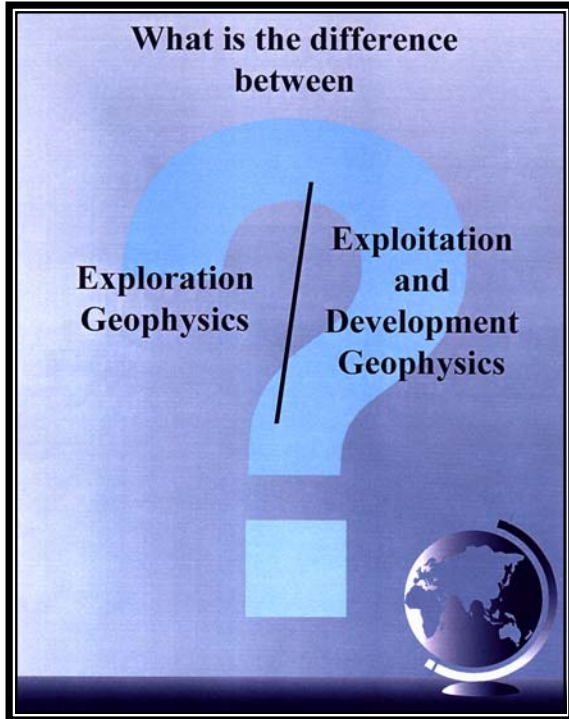


Figure 1: Exploration vs. Development Geophysics

What is the reason for the difference between exploration and development geophysics? Why are quantitative measurements using seismic data common in development geophysics, but that level of detail is not available when using seismic data for exploration? The difference is that in development geophysics one works with *calibrated seismic data*, whereas in exploration seismic data are not calibrated. Calibration uses well log data with very good vertical resolving power to determine the image of the lower resolution seismic data. With the vertically-calibrated seismic data a seismic interpreter can move away from the well location where the calibration was performed to unknown areas in the subsurface with calibrated seismic data and use its improved resolving power to make detailed quantitative estimates of reservoir properties.

The Dimension of Resolution

The two primary earth acoustic properties that affect the earth's seismic response are velocity and density, and the product of velocity and density is acoustic impedance. Changes in acoustic impedance cause seismic reflections. Therefore, the two most important logs to the seismic process are the sonic and density logs. These logs are able to vertically resolve intervals two feet thick, but they are only able to investigate six to eight inches away from the well bore. On the other hand, seismic data are not capable of two-foot vertical resolution, but the horizontal resolving power of seismic data is as large as the seismic survey. This leads to the basic difference in the dimension of resolution between logs and seismic data. *Sonic and density logs have excellent vertical resolution and poor horizontal resolution, whereas seismic data have excellent horizontal resolution and poor vertical resolution.*

At a well location the vertically resolved log data are used to build a detailed picture of the acoustic properties of the subsurface. The poorer vertically resolved seismic data are calibrated at the well location. Finally, the horizontal resolving power of the seismic data is used to move away from the well location into the unknown. The calibrated seismic data will have better resolving power than uncalibrated seismic data. The calibrated seismic data will not have as much vertical resolution as log data, but one cannot afford to drill wells at 50-100 foot spacing throughout a reservoir, whereas collecting seismic data at that interval is feasible. The calibrated seismic data show the variation of

a reservoir property throughout the reservoir better than log data.

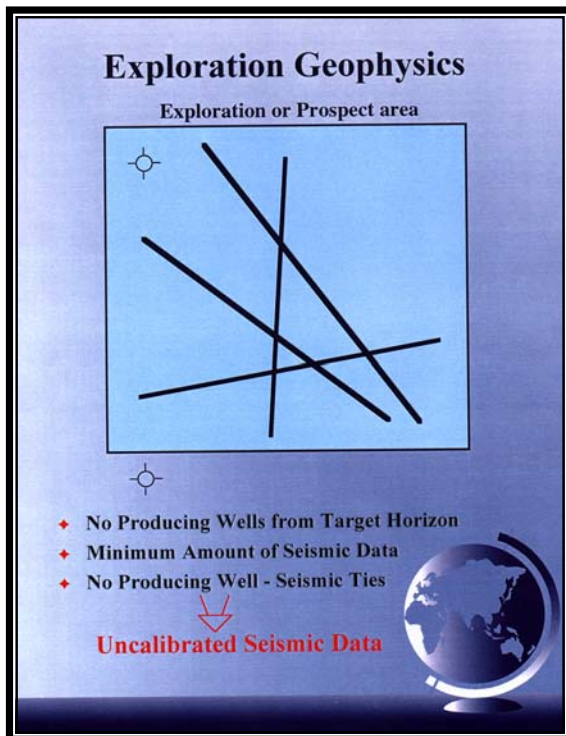


Figure 2: An Exploration Project

Seismic Resolution in Exploration

Figure 2 shows a diagram where the area in light blue is defined as the exploration or prospect area. Assume one is exploring this area for a target horizon, and there are no producing wells in the exploration area producing from the target area. There may be wells that produce from the target horizon outside of the exploration area, and there may be dry holes or wells that produce from other horizons in the exploration area, but there are no producing wells from the target horizon in the exploration area.

A minimum amount of seismic data is shot over the area to define a prospect and reduce the risk to an acceptable level. These data may be 2D or 3D. In the diagram the black lines represent 2D seismic lines shot over the area. The seismic data in figure 2 are uncalibrated. There is no direct tie

between a producing well from the target horizon and the seismic data. It is possible to make some qualitative estimates about how changes in seismic attributes relate to changes in subsurface properties (i.e. how changes in seismic amplitude relate to changes in porosity or pore fluid), but there is no quantitative relationship between seismic attributes and a subsurface property. If, for example, one observes a decrease in amplitude of the seismic reflection marking the top of a high velocity rock unit, he might conclude that the decreased seismic amplitude is an indicator of increased porosity. If that same area was in development mode and the seismic data were calibrated, then instead of simply making a qualitative statement of improved porosity one should be able to make a quantitative statement that the observed seismic signature represents x feet of y% porosity.

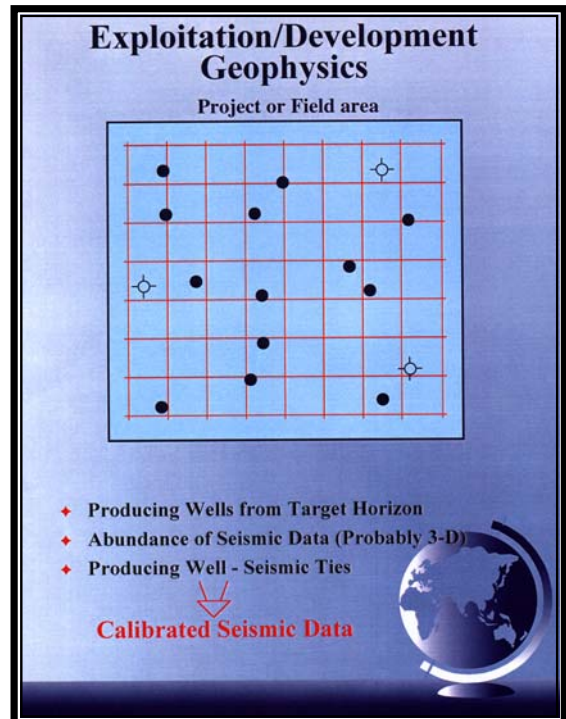


Figure 3: An Exploitation or Development Project

Exploitation and Development

Once a discovery well is drilled, the area transitions into its exploitation and

development stages. Figure 3 shows the diagram of exploitation and/or development. The light blue area represents the field. There are several producing wells, and additional seismic data (probably 3D) have been shot over the area. The important difference between this situation and exploration is that now there are direct ties between producing wells from the target horizon and seismic data. At each location where a well ties the seismic data the seismic response to the reservoir is known, and the logs measure the acoustic properties of the reservoir. A reservoir property is selected and used to calibrate the seismic response to changes in it. If, for example, there is a well with 10 feet of productive interval, one with 25 feet, and another with 40 feet, and each of the wells ties the seismic data, then one can interpolate and extrapolate to determine the seismic response for various pay thicknesses. Once the seismic data set is calibrated, one can move to any location in the data set and make a quantitative estimate of the target horizon reservoir property (i.e. pay thickness) for which the calibration was performed. The closer the location to a well the more confidence one can put in the reservoir property estimate. To map another reservoir property one needs to go through the calibration process for the second reservoir property.

The Calibration Process

The calibration process consists of two steps or two calibrations, and it is diagrammed in figure 4. First, select a reservoir property that is to be estimated using seismic data. Porosity is probably the reservoir property most often mapped with seismic attributes, but with careful calibration other reservoir properties can also be quantitatively estimated. More than one reservoir property can be measured with seismic attributes, but only one reservoir property can be evaluated at a time. The first calibration determines how the acoustic properties of the reservoir change as the chosen reservoir property varies. The upper box in figure 4 represents the chosen reservoir property, and to the left of the box is a list of some reservoir properties that are of interest in reservoir development. Once the reservoir property is identified then the question becomes how does variation of that property affect the acoustic properties of the reservoir.

The acoustic properties of the reservoir are those properties that affect its seismic response. In figure 4 the acoustic properties are listed to the left of the acoustic properties box. The two most significant acoustic properties are the p-wave velocity or interval transit time and density. In many cases they are the only acoustic properties that need to be evaluated. However, there are some reservoir properties (i.e. pore fluid, fracturing, etc.) that are best evaluated using Poisson's ratio and shear wave (s-wave) velocities in addition to p-wave velocity and density.

The last two acoustic properties in the list on the left of figure 4 (structure and thickness) are not actual acoustic properties. They are listed because changes in thickness and structure in some cases will cause changes in the seismic attributes that are similar to variations caused by changes in

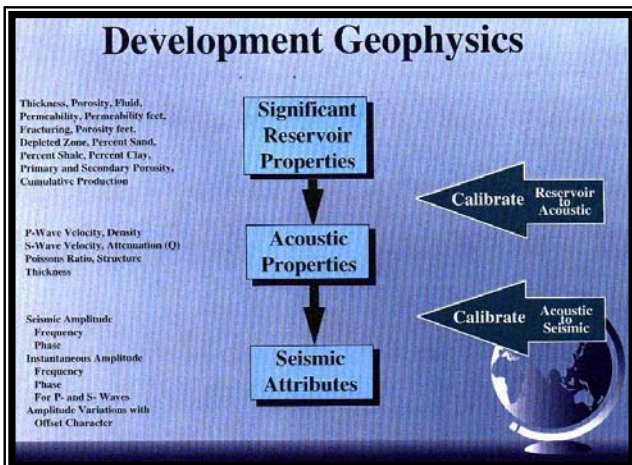


Figure 4: The Calibration Process

the acoustic properties. Even though thickness and structure are reservoir properties, they sometimes act like acoustic properties and therefore they are in this list.

When a reservoir is less than 30-50 feet thick the reflections from its top and base interfere. Changes in the thickness of a thin reservoir will cause the seismic attributes to change in a similar manner as if the acoustic properties of the reservoir changed. One must take this effect into account when interpreting reservoir properties from seismic attributes.

Once the relationship between the reservoir property and the acoustic properties is established, then the second calibration determines how changes in the acoustic properties affect the seismic attributes. Some seismic attributes are listed to the left of the seismic attributes box in figure 4. Besides the direct attributes that are listed in the figure, there are many ratios of attributes (i.e. ratio of the amplitude of a trough to the peak below it). The last attribute listed is seismic character, and it is a qualitative measure of change in amplitude and shape of a reflection moving along a seismic line or through a data volume.

The first calibration in figure 4 (reservoir property to acoustic properties) is often neglected because the ultimate goal is to determine how a change in a reservoir property affects the seismic response. However, to do a good job of calibration, one should establish the relationships between the chosen reservoir property and the acoustic properties, and then learn how the changes in the acoustic properties change the seismic response. Some of the seismic attribute and geostatistical techniques currently used simply look for a statistically significant correlation between a reservoir property and seismic attributes. They do not make any attempt to document how changes in the reservoir property alter

the acoustic properties of the reservoir. Nevertheless, the relationships that build the most confidence are those where both calibration steps have been established.

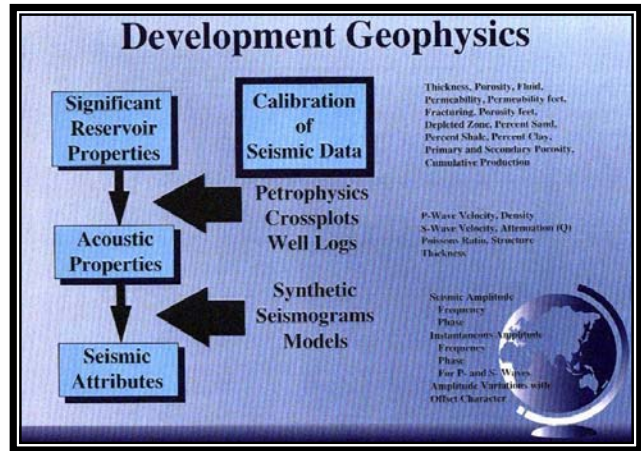


Figure 5: The Techniques of Calibration

Since two calibrations should be performed, how are they executed? Figure 5 shows the tools and techniques that are used to make each of the calibrations. The calibration of a reservoir property to the acoustic properties uses petrophysics, log data and crossplots to determining the relationships. Data and logs from wells in the field are used to crossplot relationships between the reservoir property and the acoustic properties. The goal of the first calibration is to establish a relationship between the reservoir property and each of the acoustic properties that are affected by changes in this reservoir property.

The second calibration uses seismic models and synthetic seismograms to establish the changes in seismic attributes that occur as a result of the changes in acoustic properties established in the first calibration. Seismic modeling and synthetic seismograms play a key role in determining how the seismic response changes as the reservoir property under investigation changes.

The calibration process proceeds from top to bottom in figures 4 and 5. Starting

with a reservoir property one establishes how changes in the reservoir property change the acoustic properties and how those changes affect the seismic attributes. Interpretation starts at the bottom of the figures and works up to the top. If the affected seismic attributes change by a certain amount between a well location and another location within the reservoir, what kind of changes in the acoustic properties do those changes imply and what change in the reservoir property follows?

Seismic and log data quality is a key factor in determining the level of confidence to put in reservoir property estimates. If data quality is good then the estimates can be more quantitative, and the confidence level is high. If data quality is poor the level of confidence is lower and the reservoir property estimates cannot be as detailed.

In exploitation and development situations seismic data can be used in a more

quantitative fashion than in the exploration phase because the data are calibrated at the well locations. The calibration process involves two steps:

1. Determining how changes in the reservoir property alters the acoustic properties of the reservoir. This is accomplished using logs, well data and crossplots.
2. Determining the changes in the seismic attributes that result from variations in the acoustic properties of the reservoir. This calibration uses synthetic seismograms and seismic models.

When seismic data are well calibrated, detailed measurements of subsurface properties can be made that far exceed the resolving power of the uncalibrated seismic data, and allows one to use seismic data to make quantitative estimates of reservoir properties.